**DOCKET NO. 33687**

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| **ENTERGY GULF STATES, INC.'S TRANSITION TO COMPETITION PLAN** | §<br>§<br>§ | **PUBLIC UTILITY COMMISSION OF TEXAS** |

**SPP-ETI QPR STUDY REPORT OF THE SOUTHWEST POWER POOL**

COMES NOW the Southwest Power Pool, Inc. ("SPP"), and pursuant to the order issued in this docket on October 24, 2007, files its study of the possible integration of Entergy Texas Inc. ("ETI") into SPP and implementation of retail open access ("ROA") for ETI as part of SPP ("SPP-ETI QPR Study Report" or "Report"). The SPP-ETI QPR Study is broken down into four study tracks which are included in its Report:

1. Reliability Assessment Study;
2. Market Power Study;
3. Economic Assessment Study; and
4. Retail Open Access ("ROA") Study.

The results of these four study tracks were then used to perform a Benefit/Cost Analysis, which is also included in the Report.

Pursuant to Paragraph 4 of the Protective Order filed in this docket, SPP further provides notice that the topology map identified as Appendix 2 of the Report and the Market Power Study, attached to the Report as Appendix 3, contain confidential information, and as a result, are identified as Highly Sensitive Protected Materials pursuant to the Protective Order in this docket.

The topology map provided in Appendix 2 contains Critical Energy Infrastructure Information ("CEII") as defined by the Federal Regulatory Energy Commission ("FERC"). The map contains detailed information about the transmission systems in the SPP area. Pursuant to FERC regulations, this information may only be viewed by parties who have executed a nondisclosure agreement with SPP. The Protective Order certification is not sufficient for this purpose. SPP is, therefore, unable to file this map, or provide it to requesting parties until appropriate nondisclosure agreements have been executed. Parties wishing to receive a copy of this map may contact Susan Polk at SPP at (501) 614-3260 to request a copy and execute the appropriate documentation. SPP asserts that this information is exempt from disclosure pursuant to §552.101 of the Public Information Act. This information has not been and will not be publicly disclosed by SPP. The information is relevant to the proceedings in this docket, but should not be disclosed further than such relevant uses require and should in no circumstances be disclosed outside the proceedings in this docket. Counsel for SPP has reviewed the information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the designation stated above.

Within the Market Power Study, SPP has identified certain generation-related information provided to SPP as Highly Sensitive Protected Materials by ETI. SPP will, therefore, file and provide this information only as Highly Sensitive Protected Materials. The information is relevant to the proceedings in this docket, but should not be disclosed further than such relevant uses require and should in no circumstances be disclosed outside the proceedings in this docket. SPP is also filing a public redacted version of this document.

WHEREFORE, PREMISES CONSIDERED, SPP is available to answer any questions the Commission or any interested party may have with respect to the SPP-ETI QPR Study Report.

Respectfully submitted,

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**CERTIFICATE OF SERVICE**

I hereby certify that, on December 17, 2008, a copy of this document will be served on all parties of record in this proceeding in accordance with P.U.C. PROC. R.22.74.

______________________
Shari Heino

Southwest Power Pool

# REQUIREMENTS TO INTEGRATE ENTERGY TEXAS, INC. INTO THE SOUTHWEST POWER POOL

## SPP – ETI QPR STUDY REPORT

DECEMBER 17, 2008

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# 1. EXECUTIVE SUMMARY

## 1.1. Overview

This report documents the Study that was undertaken by Southwest Power Pool, Inc. ("SPP") with input from Entergy, SPP Stakeholders, Entergy Stakeholders, ERCOT, and the Public Utility Commission of Texas ("Commission") Staff to determine the transmission system improvements that would be required to reliably and efficiently integrate Entergy Texas Inc., ("ETI") into the Southwest Power Pool ("SPP") system and the production cost savings attributable to ETI resulting from such integration ("SPP-ETI QPR Study") The SPP-ETI QPR Study results indicate that SPP is a viable QPR option for ETI. In all but one scenario[1] of all of the scenarios analyzed, net benefits to ETI resulting from ETI's Integration into SPP are positive. Details regarding the calculation of the costs and benefits included in the ETI net benefits calculations are provided in the following Sections and in additional detail within the body the SPP-ETI QPR Study Report.

Per the Commission's October 24, 2007 Order in Docket No. 33687, the SPP-ETI QPR Study parallels the Phase II Study Report – ERCOT Requirements to Integrate Entergy Gulf States – Texas into ERCOT ("Phase II Study") filed with the Commission on December 15, 2006 in this Docket. Per the Commission's May 23, 2008 Order, ERCOT is updating their Phase II Study contemporaneously with the development of the SPP-ETI QPR Study. The SPP-ETI QPR Study was performed consistent with the methodology and assumptions used in the Phase II Study, thus allowing, to the extent possible, for an "apples to apples" results comparison[2] between the integration of ETI into ERCOT described in the Phase II Study versus the integration of ETI into SPP. In addition to assessing the transmission system improvements required for the integration of ETI into SPP, Potomac Economics, LTD, at the request of SPP, performed a

[1] In this scenario, net benefits to ETI may be positive depending on economic transmission project cost allocation assumptions.

[2] While SPP coordinated with ERCOT to ensure that the data inputs, assumptions and modeling techniques were as consistent as possible, inherent differences between the two systems necessitated some differing inputs and results.

Market Power Study to assess any potential market power within the integrated ETI/SPP system. SPP also assessed the potential ETI production cost savings associated with the Integration of ETI into SPP under two gas price forecast assumptions, a 2012 base assumption of $11.00/MMBTU and a 2012 sensitivity gas price forecast assumption of $7.00/MMBTU, consistent with the assumptions used in the Phase II Study. SPP then developed estimated costs for the implementation of Retail Open Access ("ROA") for ETI following integration into SPP. Finally, SPP performed an ETI Benefits to Costs Analysis relating to Integration of ETI into SPP by comparing the potential production cost savings, for both gas price scenarios, to the capital costs of the transmission system improvements and ROA implementation.

## 1.2. Methodology

In order to evaluate the benefits to ETI of integrating into SPP, SPP created a transmission model for 2012 representing ETI's current state of operation ("Status-Quo Case"). The Status Quo Case includes transmission projects currently budgeted in the ETI Transmission Construction Plan, transmission projects identified in the SPP Transmission Expansion Plan ("STEP") and certain Entergy proposed transmission projects for 2012, the costs of which are not included in the Benefit to Cost Analysis as these projects would be required independent of the ETI integration into SPP.

Next, SPP developed a case ("ETI/SPP Integration Case") that included all of the transmission projects in the Status-Quo Case plus the minimum set of transmission projects ("Reliability Projects") required to reliably serve the load in SPP based on SPP planning criteria ("SPP Criteria"). In addition to the Reliability Projects, SPP also included one project that was justified on an economic basis[3] and one project[4] to assure that sufficient Available Transmission Capability ("ATC") into ETI would be available to alleviate any market power concerns, both of which were classified as "Economic Projects". SPP included a new Weber-Richard 500 kV line in the ETI/SPP Integration Case as a base assumption because of uncertainty regarding the ETI ATC value, as raised by Entergy, if this line was not included. SPP also evaluated the ETI

[3] The Mt. Olive to Hartburg 500 kV line series compensation at a cost of $10 Million, which increased the thermal rating from 1050 MW to 1450 MW.

[4] A new Weber to Richard 500 kV line at a cost of $229 Million.

benefits under the assumption that the Weber-Richard 500 kV line was not required for ATC purposes.

Additionally, because of the potential for Cottonwood to exit the Eastern Interconnection ("EIC") and integrate directly into ERCOT, SPP also evaluated the ETI integration into SPP assuming that Cottonwood was not part of the EIC. In order to perform this analysis, SPP created a separate set of cases: a second Status-Quo Case with Cottonwood as part of ERCOT and a second ETI/SPP Integration Case with Cottonwood as part of ERCOT. For the second Status Quo Case, in addition to all of the transmission projects included under the Cottonwood in EIC Status Quo Case, the new Weber-Richard 500 kV line was also included as this line is required for reliability purposes if Cottonwood exits the EIC. For the second ETI/SPP Integration Case, the same transmission projects that were included in the Cottonwood in EIC ETI/SPP Integration Case were also included.

### 1.3. Benefit/Cost Analysis Results

The Benefit/Cost Analysis compares the benefits to ETI associated with integration into SPP to the associated costs to ETI, as calculated in accordance with the study tracks defined under Section 2 of this Report, through calculation of an ETI Benefit-to-Cost Ratio ("BC Ratio"). The ETI BC Ratio is calculated, for all scenarios, as: ([ETI production cost savings / 0.18[5]] / [Reliability Project capital costs + Economic Project capital costs + ROA implementation capital costs]). A BC Ratio of less than 1.0 indicates a net negative benefit and a BC Ratio of greater than 1.0 indicates a net positive benefit. A BC Ratio equal to 1.0 indicates a break-even situation. Based on this calculation, the ETI BC Ratios for each scenario are summarized in Table I.

[5] Consistent with the Phase II Study, in order to directly compare the production cost savings to the cost of the Reliability Projects, Economic Projects and ROA implementation for Benefit/Cost Analysis purposes, the production cost savings is divided by the assumed annual carrying charge rate. SPP uses an 18% carrying charge rate assumption in its Balanced Portfolio analysis process as compared to the 16.67% assumption used in the Phase II Study.

For the Cottonwood in EIC assumption, SPP calculated a range of potential ETI 2012 annual net benefits reflecting the assumption regarding inclusion or exclusion of the new Weber-Richard 500 kV line. For the $11.00 gas price assumption, ETI net benefits range from a low of $97.8 Million if the line is included to a high of $201.5 Million if the line is excluded. For the $7.00 gas price assumption, ETI net benefits range from a low of ($105.9) Million if the line is included to a high of $57.9 Million if the line is excluded, thus indicating a potential net negative benefit to ETI under the $7.00 gas price assuming the new Weber-Richard line is included. However, for all BC Ratio calculations, SPP used conservative assumptions by including the entire cost of the Economic Projects under the cost side of the equation. Based upon current cost allocation methodologies within Entergy and SPP regarding cost responsibility for Economic Projects, some of the Economic Project costs could be borne by parties other than ETI, which could result in increased net benefits to ETI under the Cottonwood in EIC assumption assuming inclusion of the Weber-Richard 500 kV line, which could ultimately equate to an ETI net positive benefit under the $7.00 gas price assumption.

Under both the $11.00 gas price and $7.00 gas price assumption for the case where Cottonwood moves into ERCOT, 2012 annual net benefits to ETI remain positive, ranging from $36 Million for the $7.00 gas price assumption to $61.4 Million for the $11.00 gas price assumption.

**Table I – ETI Benefit/Cost Analysis Summary**

| Scenario | Production Cost Savings $MM | Equivalent Capital Cost $MM | Reliability Project Costs $MM | Economic Project Costs $MM | ROA Costs $MM | Net Benefit $MM | BC Ratio |
|---|---|---|---|---|---|---|---|
| **1** | 80.4 | 446.6 | 105 | 239 | 4.8 | 97.8 | 1.28 |
| **2** | 43.7 | 242.9 | 105 | 239 | 4.8 | (105.9) | 0.70 |
| **1A** | 57.8 | 321.3 | 105 | 10 | 4.8 | 201.5 | 2.68 |
| **2A** | 32.0 | 177.7 | 105 | 10 | 4.8 | 57.9 | 1.48 |
| **3** | 32.6 | 181.2 | 105 | 10 | 4.8 | 61.4 | 1.51 |
| **4** | 28.0 | 155.8 | 105 | 10 | 4.8 | 36.0 | 1.30 |

Scenario 1 - Cottonwood in EIC - $11.00 Gas – With Weber-Richard 500 kV line
Scenario 2 - Cottonwood in EIC - $7.00 Gas – With Weber-Richard 500 kV line
Scenario 1A - Cottonwood in EIC - $11.00 Gas – Without Weber-Richard 500 kV line
Scenario 2A - Cottonwood in EIC - $7.00 Gas – Without Weber-Richard 500 kV line

Scenario 3 - Cottonwood in ERCOT - $11.00 Gas
Scenario 4 - Cottonwood in ERCOT - $7.00 Gas

The results presented above, which include costs of both Reliability Projects and Economic Projects, indicate, in all except the $7.00 gas price assumption with Cottonwood in EIC, that net benefits to ETI are positive. Additionally, based upon historical average on-peak wholesale electricity prices for the October 2007 through October 2008 period[6] for SPP and ERCOT, the ETI integration into SPP is the better choice. During this period, SPP's average on-peak wholesale price was approximately $39/MWh as compared to ERCOT's average on-peak wholesale price of approximately $61/MWh, indicating increased opportunity for retail rate reductions in ETI through integration into SPP versus integration into ERCOT, assuming savings at the wholesale level are passed through to retail.

## 1.4. Transmission Project Costs

The total cost associated with the Reliability Projects to meet SPP Criteria for the Cottonwood in EIC assumption is estimated at $105 Million and the total cost of the Economic Projects is estimated at $239 Million, under the assumption that a new Weber-Richard 500 kV line is required for ETI ATC purposes to alleviate potential market power concerns, resulting in a total transmission project cost of $344 Million included as a cost in the Benefit/Cost Analysis. The total transmission project cost for the Cottonwood in EIC assumption is estimated at $115 Million assuming that a new Weber-Richard 500 kV line is not needed to maintain adequate ETI ATC levels to alleviate market power concerns.

The total cost of Reliability Projects to meet SPP Criteria for the Cottonwood in ERCOT assumptions remains at $105 Million. However, under the Cottonwood in ERCOT assumption, the new Weber-Richard 500 kV line would be required for reliability purposes in both the Status-Quo Case and the ETI/SPP Integration Case and therefore, the $229 Million cost is not included as a cost in the Benefit/Cost Analysis as this project would be required irrespective of

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[6] See October 2008 Monthly State of the Market Report at:
http://www.spp.org/publications/200810%20-%20SPP%20Monthly%20State%20of%20the%20Market%20Report%20-%20October%202008.pdf

ETI integration into SPP. Therefore, the total cost of the Economic Projects for the Cottonwood in ERCOT assumptions is $10 Million, resulting in a total transmission project cost of $115 Million that is included as a cost in the Benefit/Cost Analysis. A breakdown of the Reliability Projects and Economic Projects, along with key transmission analysis assumptions, is shown in Table II. A detailed list of the Reliability Projects and Economic Projects is included in Section 4.

**Table II – Summary of Assumptions and Transmission Projects**
**Transmission Projects**

| | |
|---|---|
| Projects to meet SPP Criteria where costs are included in Benefit/Cost Analysis – ETI/SPP Integration Case. | • New Orange County Substation work ($50 M)<br>• Local 138 kV and 69 kV upgrades($55 M) |
| Economic Projects where costs are offset by production cost savings and are included in the Benefit/Cost Analysis | • New Weber-Richard 500 kV line ($229 M)<br>  o Only under Cottonwood in EIC assumption. Cost excluded under Cottonwood in ERCOT assumption.<br>• Mt. Olive-Hartsburg Series Compensation ($10 M) |
| Projects identified to alleviate potential market power concerns with ancillary economic benefits that are classified as Economic Projects | • New Weber-Richard 500 kV line ($229 M) [Note: this is part of the Status-Quo Case for the Cottonwood in ERCOT analysis] |
| Budgeted and Planned Projects – Costs not included in Benefit/Cost Analysis – Both Status Quo Case and ETI/SPP Integration Case | • ETI Proposed Projects for 2012<br>• Local Reliability projects for Western Region<br>• Transmission Reliability projects from the 2007 approved STEP plan<br>• ETI Transmission Construction Plan |

### 1.5. Market Power Study

As discussed in detail in Section 5, the results of the Market Power Study did not identify any market power issues associated with the ETI integration into SPP in 2012 when the Weber-Richard 500 kV line is included in the analysis, which provides for an ETI ATC of 1224 MW for the Cottonwood in EIC assumption and an ETI ATC of 1355 MW for the Cottonwood in ERCOT assumption. If the Weber-Richard 500 kV line is not included for the case where Cottonwood remains in EIC, the ETI ATC drops to 899 MW and some redispatch of the Entergy system would be required at times to maintain this 899 MW ATC level. As a result, SPP included a sensitivity analysis which excluded the Weber-Richard 500 kV line from the ETI/SPP Integrated Case (Cottonwood in EIC). Assuming the 899 MW of ETI ATC can be maintained without the Weber-Richard line, its removal will have little to no impact on the Market Power Study results. The Market Power Study included projects from the Status-Quo Cases and the identified Reliability Projects and Economic Projects as inputs into the analysis. Results of the Market Power Study indicated that no additional transmission projects were required.

## 1.6. Annual Production Cost Results - 2012

The total reduction in ETI production costs resulting from the integration into SPP, assuming Cottonwood remains in EIC and an $11.00 gas price, is estimated at $80.4 Million. For the Cottonwood in ERCOT and $11.00 gas assumptions, the total reduction in ETI production costs resulting from the integration into SPP is estimated at $32.6 Million. The total reduction in ETI production costs resulting from the integration into SPP, assuming Cottonwood remains in EIC and a $7.00 gas price, is estimated at $43.7 Million. For the Cottonwood in ERCOT and $7.00 gas assumptions, the total reduction in ETI production costs resulting from the integration into SPP is estimated at $28.0 Million. A detailed discussion of the assumptions and methodology used to estimate the ETI production cost savings is included in Section 6.

## 1.7. Retail Open Access ("ROA") Implementation

SPP analyzed the functions required to implement ROA in SPP for ETI. This process began with the creation of a list of functional areas to be evaluated for system changes and labor impacts. SPP worked with ERCOT staff to confirm its assumptions and address cost estimates. After identifying the necessary functions, impacts, system changes, and additional staffing requirements needed to manage the ROA function, SPP developed low and high range estimates for implementation. Based on the set of assumptions included in Section 7, the capital cost implementation range is estimated to be from $2.3 Million to $4.7 Million and ongoing maintenance costs are estimated to be in the range of $415,000 to $1.2 Million. Only capital costs were included in the Benefit/Cost Analysis.

### 1.8. Summary

The SPP-ETI QPR Study results indicate that SPP is a viable QPR option for ETI. In all scenarios except the ETI/SPP Integration Case, Cottonwood in EIC, $7.00 gas price and inclusion of the new Weber-Richard 500 kV line scenario, net benefits to ETI resulting from ETI's Integration into SPP are positive. The negative net benefits for this scenario are driven by two assumptions: (1) that the new Weber-Richard line is needed to alleviate market power concerns; and (2) that the full cost of the Weber-Richard line is allocated to ETI, consistent with the allocation of costs associated with Reliability Projects. If 46% or more of the $229 Million cost of the Weber-Richard line were allocated to parties other than ETI, the case would produce net positive benefits to ETI. Additionally, if it is determined that the new Weber-Richard line is not needed to alleviate market power concerns, this case would produce positive net benefits to ETI.

Details regarding the calculation of the costs and benefits included in the ETI net benefits calculations are provided within the body the SPP-ETI QPR Study Report.

## 2. Introduction

Per the October 24, 2007 Order of the Commission in this Docket, SPP has been requested by ETI to perform an analysis similar to the ERCOT Phase II EGSI-TX Integration Report prepared by ERCOT to provide a Benefit/Cost Analysis for the integration of ETI into SPP to enable retail competition in ETI.

The SPP-ETI QPR Study is broken down into four study tracks: (1) Reliability Assessment Study; (2) Market Power Study; (3) Economic Assessment Study; and (4) Retail Open Access ("ROA") Study. Each study track report provides an overview of the assessment and discusses the processes, tools, assumptions, details, and results achieved. The results of each study track were then used into the Benefit/Cost Analysis discussed in Section 8.

Throughout the process, SPP worked closely with ETI personnel and interested stakeholders to identify, evaluate, and review the input assumptions and results of each study track. SPP and ETI collaborated throughout the study process to verify the accuracy of the input data and review the analysis results to ensure the results were reasonable. This iterative process enabled SPP to complete the SPP-ETI QPR Study in a systematic and reasonable manner.

Stakeholder meetings were held in February, April, June, September, and December of 2008 in Austin, Texas in order to facilitate optimal stakeholder participation specifically for ERCOT staff and Commission Staff. Invitees included SPP Staff, SPP Stakeholders, Entergy, Entergy Stakeholders, ERCOT Staff, all parties to Docket 33687, and Commission Staff. Materials and minutes from all Stakeholder meetings are posted at www.spp.org.

## 3. Requirements

The primary requirement for the SPP-ETI QPR Study was to ensure that the integration of ETI into SPP could be accomplished in conformity with the SPP Criteria and NERC Transmission Planning ("TPL") standards in order to serve the combined SPP-ETI load reliably. Additionally, SPP was to propose appropriate market power mitigation measures, if necessary, to meet the requirements for achieving ROA in the ETI region, assess the potential savings of economic upgrades to serve the combined load, assess the net benefits or costs to support ROA in the

ETI region and assess the implementation and ongoing costs necessary to support ROA in the ETI region.

In developing the results, SPP incorporated the following assumptions:

1. The SPP-ETI QPR Study used the most up-to-date information available with respect to input parameters such as the transmission topology, planned upgrades, and fuel prices, with the expectation that certain input information used will differ from the Phase II Study due to the availability of more up-to-date information. Additionally, input assumptions for the SPP-ETI QPR Study were consistent with the assumptions used in the ongoing Cost Benefit Task Force – Cost Benefit Study for Future Market Design.[7]

2. ETI, and any entering Retail Electric Providers, will participate in the SPP markets the same as all other Market Participants.

3. ETI would unbundle into separate affiliated entities for each of its electric market activities (wires, generation, and retail). For ease of reference, however, any reference to ETI can be considered a reference to ETI and its affiliates.

4. The ETI transmission facilities will be placed under the SPP Open Access Transmission Tariff ("OATT") and all existing long-term firm transmission system contracts will be honored.

5. The Existing ERCOT market rules related to ROA will be used as much as possible.

## 4. Reliability Assessment Study

### 4.1. Study Process

The Reliability Assessment Study was performed to identify expected system conditions for the ETI and SPP systems for 2012 assuming ETI remained within Entergy ("Status-Quo Case") and

[7] Further details regarding this Study can be found at:
http://www.spp.org/committee_detail.asp?commID=73

to identify incremental transmission system upgrades required for the reliable integration of ETI into SPP ("ETI/SPP Integration Case"). Additionally, any upgrades required for mitigation of market power identified in the Market Power Study were to be identified separately. The SPP-ETI QPR Study process is consistent with the process used in the Phase II Study. Sensitivity cases were also evaluated assuming Cottonwood exits the EIC ("Status-Quo Case – Cottonwood in ERCOT", ETI/SPP Integration Case – Cottonwood in ERCOT"). The transmission system models identified in the Status-Quo, Status-Quo – Cottonwood in ERCOT, ETI/SPP Integration, and ETI/SPP Integration – Cottonwood in ERCOT Cases were used as inputs into the Economic Assessment Study that is discussed in Section 5 below.

SPP worked closely with Entergy transmission personnel to review and finalize the network topology used in the reliability studies. Entergy transmission personnel provided ETI's Transmission Construction Plan and assisted in the review of the reliability run results to ensure all known constraints were properly addressed.

### 4.2. Tools

In developing the reliability study assessments, SPP used the same processes and tools currently used for its own reliability assessments and transmission planning process set forth in the SPP OATT.

The tools used by SPP for the Reliability Assessment analysis were Siemens's Power System Simulation for Engineers ("PSS/E") and Managing and Utilizing System Transmission ("MUST") software tools. As with the annual SPP Transmission Planning Process, the goal is to assess the reliable delivery of electricity to consumers and identify transmission projects that would be needed to meet the SPP Criteria and NERC TPL standards.

### 4.3. Power Flow Case Development and Key Assumptions

The Status-Quo Case started with a 2012 Summer Peak case that was developed as a part of the SPP Model Development Working Group ("MDWG") 2007 series models. The study year 2012 was selected as the appropriate timeframe and agreed upon by SPP, ERCOT and ETI. The model details were verified and updated based upon collaboration with ETI personnel and input from other stakeholders.

The following key assumptions were used to develop the Status-Quo Case:

1. The ETI system was represented as a separate balancing authority area for modeling purposes.
2. All transmission upgrade projects with in-service dates in the 2012 timeframe that are approved and budgeted by Entergy and SPP for construction were modeled. This included all related projects identified in Entergy's Transmission Construction Plan and the related projects identified in Appendix B of the 2007 SPP Transmission Expansion Plan ("STEP")[8].
3. All transmission projects currently proposed by Entergy for 2012 system conditions were examined by SPP staff. These projects are intended to address potential thermal and voltage violations based on single contingency events ("N-1"). A detailed list of the budgeted and proposed Entergy transmission projects is included in Appendix 1. After reviewing these upgrades, only selected projects were deemed necessary to address reliability criteria in the ETI area and these projects were included in the analysis. In addition, the upgrade of the Apollo-Porter 138 kV line was added to the Status Quo Case as this project is needed to maintain the local reliability in the Western region of ETI.
4. The Cottonwood unit is connected in the ETI area with a net output of 703 MW. The Cottonwood output was determined to be the combination of a 600 MW firm transmission reservation to Louisiana Generating, LLC ("LAGen") and 103 MW provided to Entergy System Planning and Operations.

These projects and assumptions represent the final set of projects and assumptions that were included in the Status-Quo Case.

The ETI/SPP Integration Case includes all of the assumptions and transmission projects identified in the Status-Quo Case plus all incremental transmission upgrades required for reliable integration of ETI into SPP, plus two additional transmission upgrades classified by SPP as Economic Upgrades. The incremental transmission upgrades for reliable integration are

[8] STEP plan can be found at SPP's website (http://www.spp.org/section.asp?group=1155&pageID=27)

required to address SPP Planning Criteria only. SPP Planning Criteria requires (N-1) contingency flows on all transmission lines of no greater than 100% of thermal rating and that (N-1) contingency bus voltages must be greater than or equal to 0.9 per unit. To determine what incremental upgrades were needed, SPP analyzed the reliability effects of a set of contingencies represented by breaker-to-breaker transmission outages for the combined SPP and ETI system. This analysis included monitoring of all transmission elements in the combined SPP and ETI system with voltage levels 69 kV and above to identify reliability issues. In addition, all the transmission contingencies (breaker-to-breaker) 230 kV and above for the rest of the Entergy system were analyzed. The resulting projects are referred to as Reliability Projects and the costs of these projects are included in the Benefit/Cost Analysis calculations. Table III shows a list of projects and high level cost estimates associated with these Reliability Projects.

**Table III –Reliability Project Cost Estimates**

| Project Description | High Level Direct Cost Estimate |
|---|---|
| Construct New Orange County 230 KV Substation | $50,000,000 |
| Upgrade Jacinto-Splendora 138 KV | $7,850,700 |
| Upgrade Fish Creek-Longmire 138 KV | $3,660,000 |
| Upgrade Lewis Creek-Egypt 138 KV | $2,311,900 |
| Upgrade Jasper-Rayburn 138 KV | $8,235,000 |
| Upgrade Tubular-Dobbin 138 KV | $11,352,100 |
| Upgrade Fish Creek-Spring Branch 138 KV | $5,856,000 |
| Upgrade Transco-SaratogaTap_69kV | $4,260,000 |
| Upgrade Dome-Sour Lake 69 KV | $1,020,000 |
| Upgrade Dome-Transco 69 KV | $3,420,000 |
| Upgrade Elizabeth-Gallier 69 KV | $1,620,000 |
| Upgrade Apollo-Splendora 138 KV | $1,647,000 |
| Upgrade Cedar Hill-Conroe 138 KV | $3,233,000 |
| Upgrade Goodrich-Port Neches 69 KV | $600,000 |
| **Total** | **$105,065,700** |

Two additional projects were identified by SPP to be included in the ETI/SPP Integration Case: (1) Series compensation on the Mt. Olive to Hartburg line, increasing its thermal rating from 1050 MW to 1450 MW at an estimated cost of $10 Million and (2) the addition of a new

Weber-Richard 500 kV line at an estimated cost of $229 Million. As further discussed in Section 4.7, SPP has included the new Weber-Richard 500 kV line to alleviate potential market power concerns in the case where Cottonwood generation remains in EIC as a base assumption and SPP has also included a sensitivity case where the new Weber-Richard line is not included. In addition to alleviating potential market power concerns through the increase of ATC to ETI, the Weber-Richard 500 kV line project produces ancillary economic benefits through the increase in ATC, reduction in congestion in the Cottonwood area, and a reduction in voltage-related Reliability Must Run ("RMR") requirements in the Sabine area, resulting in SPP classifying this project as economic. Based on observed congestion hours and redispatch costs from the production cost analysis prior to upgrading the Mt. Olive to Hartburg line, this project is appropriately classified as economic.

### 4.4. Study Results - Cottonwood in ERCOT

SPP conducted a sensitivity analysis based on the likelihood that the Cottonwood units may exit the EIC and move to ERCOT as allowed by FERC's March 15, 2007 Order Granting Petition for Declaratory Order[9], in which FERC granted Cottonwood's petition for a declaratory order disclaiming jurisdiction over the proposed transmission line to ERCOT. Kelson Transmission Company, LLC's application for a Certificate for Convenience and Necessity is the subject of PUCT Docket No. 34611.[10] In this analysis, SPP followed the same approach as described in Section 4.3. The possible removal of Cottonwood from the EIC necessitated the creation of a Status-Quo Case – Cottonwood in ERCOT and an ETI/SPP Integration Case – Cottonwood in ERCOT. For the Status-Quo Case – Cottonwood in ERCOT, the new Weber-Richard 500 kV line is required for reliability purposes and, as such, the $229 Million cost is not included as a cost in the Benefit/Cost Analysis as this cost would be incurred irrespective of the ETI integration into SPP. For the ETI/SPP Integration Case – Cottonwood in ERCOT, the same set of remaining Reliability Projects and Economic Projects required in the ETI/SPP Integration Case (Cottonwood in EIC) is also required.

[9] 118 FERC ¶ 61,198 – Docket EL06-87-000.

[10] A hearing has been held, but parties have not yet filed briefs.

### 4.5. Stability Analysis

PowerTech Labs, Inc. ("PowerTech") was selected to perform an analysis of the dynamic performance of the system in the seconds following a fault or other disturbance. This type of analysis is required to ensure that the connections between the SPP and ETI regions are sufficient such that the system will remain stable following an instantaneous disturbance (such as the loss of additional generation or transmission outages).

These dynamic analyses require modeling of the topology of the grid, the dynamic response of individual generators and of aggregated electrical loads (motors, lights, etc.). Due to the complexity of this analysis, PowerTech will not complete its final analysis until the first quarter of 2009.

Based on preliminary study results, no angular stability problems were identified. However, as part of the voltage security analysis, generator-to-generator transfers were simulated along with generator-to-load transfers. Based on these preliminary results, it can be concluded that the Lewis Creek Units are critical to the ETI region and are required to be must-run at minimum output for all hours to enhance the transfer capability into the ETI region and maintain voltage security. The preliminary results also indicate that one of the two large Sabine units connected to the ETI 230 kV system is also needed in the summer months to support voltage in the Eastern part of the ETI system.

A copy of the Preliminary PowerTech report is attached as Appendix 6. Upon completion of the PowerTech final analysis, SPP will submit an update to the PUCT indicating whether any updates or revisions to the SPP-ETI QPR Study are necessary.

### 4.6. Transfer Capability Assessment into ETI

SPP also determined the transfer capability into ETI for the ETI/SPP Integration Case and the ETI/SPP Integration Case – Cottonwood in ERCOT for use in the Market Power Study using the same methodology SPP uses for calculating transfer capability on the SPP system. For this analysis, SPP simulated an import into ETI from the outside (50% SPP and 50% non-ETI Entergy). Available Transmission Capability or FCITC ("First Contingency Incremental Transfer Capability") was originally calculated at 899 MW for the ETI/SPP Integration Case (Cottonwood in EIC), assuming the Weber-Richard 500 kV line was not added. Discussion between SPP and Entergy staff regarding the certainty of the 899 MW FCITC value[11] prompted SPP to include the new Weber-Richard 500 kV line as a base assumption to ensure that a firm FCITC value could be used in the Market Power Analysis[12]. Table IV shows a summary of the components used to arrive at the ATC values, with and without the Weber-Richard 500 kV line.

**Table IV – Summary of ATC Calculations**

| Case | TTC[13] (MW) | Firm Capacity [14] (MW) | Incremental ATC[15] (MW) | Net ATC[16] (MW) |
|---|---|---|---|---|
| **ETI/SPP Integration Case – without Weber-Richard 500 kV line** | 1738 | 839 | 0 | 899 |
| **ETI/SPP Integration Case with Weber-Richard 500 kV line** | 1738 | 839 | 325 | 1,224 |
| **ETI/SPP Integration Case – with Weber-Richard 500 kV line** | 1838 | 839 | 356 | 1,355 |

## 4.7. Summary

The Reliability Assessment Study was performed based on the assumption that ETI will become a full member of SPP and place its transmission facilities under the SPP OATT (Open Access Transmission Tariff). This assessment was consistent with the type of assessment that SPP Staff would perform to add any other new member (e.g. Nebraska Entities).

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[11] Redispatch within the Entergy system outside of ETI would be required to maintain the 899 MW FCITC value, which could not be guaranteed.

[12] Assuming a zero ATC value in the Market Power Analysis would have created market power concerns, as compared to relying upon the 899 MW FCTIC value.

[13] Total Transfer Capability excluding Reliability Projects
[14] Reserved Long-Term Firm Transmission Service
[15] Additional ATC from Reliability and Economic Projects
[16] TTC – Firm Capacity + Incremental ATC

The Reliability Assessment Study performed by SPP Staff indicates that approximately $105 Million of Reliability Projects in the ETI area are needed to comply with the SPP Criteria. This investment does not vary as a result of Cottonwood moving into ERCOT or under the base Tenaska-Frontier firm contract assumption. If Tenaska-Frontier's firm contract beyond 2010 is honored due to rollover rights, the cost of the Reliability Projects drops to approximately $42 Million if Cottonwood remains in EIC or to approximately $34 Million if Cottonwood moves to ERCOT.

In addition to the Reliability Projects, SPP has identified two additional transmission projects applicable to the ETI/SPP Integration Cases (Cottonwood in EIC) for inclusion in the Benefit/Cost Analysis under the base assumption: (1) the upgrade of the Mt. Olive to Hartburg 500 kV line, which is justified based on economics, and (2) the addition a new Weber to Richard 500 kV line, which is needed to address potential market power concerns but also provides ancillary economic benefits. Both of these projects have been classified as Economic Projects for the Cottonwood in EIC scenarios. Additionally, SPP also evaluated a sensitivity to the base assumption by not including the Weber to Richard 500 kV line.

For both the Status Quo Cases and the ETI/SPP Integration Cases for Cottonwood in ERCOT, the new Weber to Richard 500 kV line is needed for reliability purposes and, as such, its cost is not included in the Benefit/Cost Analysis as this line would be needed irrespective of the ETI integration into SPP.

Based on preliminary stability study analysis which only included the Reliability Projects, the addition of the Reliability Projects will have minimal to no impact on the RMR requirements in the Western Region (Lewis Creek units) but may reduce the voltage-related RMR requirements in the Sabine area. The addition of the Economic Projects is not expected to have any impact on RMR requirements in the Western Region but is expected to further reduce voltage-related RMR requirements in the Sabine area, subject to verification through further stability analyses.

Further, SPP Staff has concluded that as a result of the Reliability Projects and Economic Projects identified in this process, the Incremental Available Transfer Capability will be increased by approximately 325 MW in the ETI/SPP Integration Case – Cottonwood in EIC and increased by approximately 356 MW in the ETI/SPP Integration Case – Cottonwood in ERCOT.

The results of this study track were used as direct inputs into the Market Power Study and Economic Assessment Study, assuring close coordination between study tracks.

## 5. Market Power Study

Potomac Economics was engaged to perform an evaluation of market power related to ETI joining the SPP and to identify mitigation options that would address any market power issues found. This section provides a summary of Potomac's findings. A complete copy of the report is included as Appendix 3.

The study was designed to address requirements of the Public Utility Regulatory Act ("PURA") as modified by Texas Senate Bill 7.[17] There are two relevant requirements in this case; first, PURA establishes a maximum market share threshold of 20 percent for any area to be defined as a Qualified Power Region ("QPR"), [18] which is satisfied if no suppliers have a market share greater than 20 percent. In this market power analysis, an entity and its affiliates are considered a single supplier or owner. Potomac Economics analysis confirms that this test is satisfied for the combined SPP/ETI Area.[19]

Second, PURA requires that the analysis include an assessment of import capability for QPRs that are not entirely within Texas: In determining whether a power region not entirely within the state meets the requirements of this section, the commission is required to consider the extent to which the available transmission facilities limit the delivery of electricity from generators located outside the state to areas of the power region within the state.[20]

However, PURA and subsequent PUCT precedent do not provide specific guidance or requirements for the analysis necessary to satisfy this section. Hence, Potomac Economics interpreted this section as a requirement to evaluate local market power in transmission-

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17 Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §39 (PURA)

18 PURA §39.152(a)(3)

19 Throughout this report the term "ETI Area" is used to describe the area of Texas currently served by Entergy Texas, Inc. (ETI).

20 PURA §39.152(b)

constrained areas in the portions of the ETI service area ("the ETI Area"). Because transmission constraints can isolate areas with a relatively small number of potential suppliers, it is the local market power analysis that is most likely to generate the need for some form of market power mitigation.

Potomac Economics used a number of market power indicators in its analysis, which included, several measures of how concentrated the ownership of supply is in the constrained areas, as well as a determination of whether the largest supplier's resources are needed to meet the demand in the area (i.e., whether the supplier is "pivotal"). Finally, because there are significant transmission constraints that bind into and within the ETI Area, Potomac Economics defined two geographic markets for these analyses:

- The entire ETI Area; and
- The Western Subregion within the ETI Area (which is defined as the load and resources west of the Jacinto and Cypress substations).

The analysis of the local market power issues in the ETI Area indicate limited potential competitive concerns in the ETI Area or Western Sub-region. The market concentration results indicate that the market in the ETI Area will support workable competition, although the concentrations are in the highly-concentrated range. Requiring ETI to sell a portion of its capacity in the ETI Area via capacity auctions as described in PURA and PUCT rules would substantially reduce the market concentration in the area.

With regard to the pivotal supplier analysis, most scenarios show that ETI will not be pivotal (including all analyses of the Western Sub-region). In two cases where Potomac Economics found ETI to be pivotal, they also find a number of factors that significantly ease their competitive concerns. First, ETI has a number of Reliability-Must-Run (RMR) obligations in the area that compel its generation to run to support the reliability of the system which would prevent ETI from threatening to withhold supply.

Second, Potomac Economics addresses the concern in this study of whether ETI could raise prices to retail customers in the region. In scenarios that show ETI is pivotal, it is pivotal over a relatively small portion of the load. Hence, ETI would have to withhold most of its resources to raise prices to a small portion of load. Further, the magnitude of that price increase would be limited by ETI's obligations as a provider-of-last-resort ("POLR"[21]). Although the specifics of the POLR pricing provisions that would apply to ETI are unknown, it is highly unlikely that they would allow a price increase large enough to make withholding profitable in this case.

Third, in the cases where ETI is pivotal, it is only in a small number of hours. The pivotal supplier analysis uses the load forecast for the annual peak of the year. In general, the load declines sharply from the annual peak hour to other hours, which limits the extent to which ETI is pivotal. In other words, ETI's resources would only be needed to serve a portion of the load when load levels are close to the annual peak.

Finally, as a Regional Transmission Organization ("RTO"), SPP will have a market monitor and market power mitigation measures necessary to address concerns in the region. Given the vast quantities of withholding that would be necessary to exploit ETI's pivotal supplier status; its conduct would not go unnoticed by the market monitor or the Federal Energy Regulatory Commission ("FERC").

Hence, Potomac Economics found that market power mitigation measures are not necessary to address competitive issues in this case. However, if policymakers desire additional assurance that the market will perform competitively, implementing a 15 percent capacity auction as called for in PURA would lower concentration levels and reduce the extent to which ETI is pivotal. Unless additional transmission capacity can be built that produce net benefits to the region, capacity auctions are the most cost-effective form of market power mitigation.

## 6. Economic Assessment Study

### 6.1. Purpose

Ventyx Energy, LLC ("Ventyx") performed the Economic Assessment Study for this Report under the direct supervision of SPP, as it has developed its own databases containing detailed industry data that can be used independently for custom analyses or incorporated into studies using the Ventyx planning software. The quantitative economic benefit analysis combined the Ventyx

[21] This analysis assumes that there would be an ETI affiliate responsible for retail operations which would operate as a POLR.

MarketVision database and SPP-specific data, along with customized modeling parameters developed during and for this study, as inputs. SPP worked closely with ETI to verify the input data assumptions and review results. Additionally, some inputs were defined based on the Cost Benefit Task Force – Cost Benefit Study for Future Market Design. This section provides the input data assumptions used in developing the assessment results. Consistent with the reliability assessment, the economic assessment encompasses the time period of 2012.

### 6.2. Tools

Ventyx used its PROMOD IV® Full Transmission Nodal Market simulation software to evaluate ETI as a member of the SPP Market. The tools used for this study are similar to the tools ERCOT used in that it produces an hourly chronological module that simulates the generation, load and transmission constraints of a system. The module performs a security constrained commitment and dispatch every hour of the study period to meet the load. Outputs from the module are used to calculate the cost metrics for SPP and ETI.

### 6.3. Study Cases

Consistent with the Reliability Assessment Study, SPP created four base assumption study cases and one sensitivity study case for PROMOD IV® analysis, for both the $11.00 gas price assumption and the $7.00 gas price assumption:

- **Status-Quo Case (Cottonwood in EIC)** – includes all transmission projects described under Section 4 except the Reliability Projects and Economic Projects. This case represents ETI as part of the Entergy system.
- **ETI/SPP Integration Case (Cottonwood in EIC)** – includes all transmission projects described under Section 4, including the Reliability Projects and Economic Projects. This case represents ETI as part of the SPP system.
- **ETI/SPP Integration Case (Cottonwood in EIC) Sensitivity** – includes all transmission projects described under Section 4, including the Reliability Projects and Mt. Olive to Hartburg upgrade but excluding the new Weber to Richard 500 kV line. This case represents ETI as part of the SPP system.

- **Status-Quo Case – Cottonwood in ERCOT** – includes transmission projects described under Section 4, including the Weber-Richard 500 kV line but excluding the Reliability Projects and the Mt. Olive - Hartburg upgrade. This case represents ETI as part of the Entergy system and assumes that Cottonwood generation is not connected to EIC.

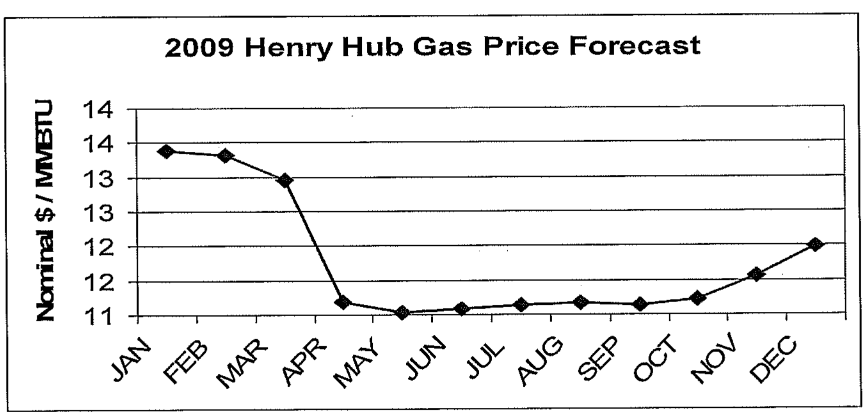
- **ETI/SPP Integration Case - Cottonwood in ERCOT** – includes all transmission projects described under Section 4, including the Reliability Projects and Economic Projects. This case represents ETI as part of the Entergy system and assumes that Cottonwood generation is not connected to EIC.

## 6.4. Key Input Assumptions

Following is a summary of key PROMOD IV® input data assumptions.

1. **Gas Price Forecasts** - The annual gas price forecast for 2012 was developed by Ventyx and is consistent with the gas price assumptions used in the SPP Cost Benefit Study for Future Markets. The annual average gas price was $11.00/MMBTU and the monthly prices were developed following the pattern shown in Table V. The monthly gas prices shown below were scaled to the annual assumed gas forecast of $11.00/MMBTU. A sensitivity was also performed assuming an annual average gas price of $7.00/MMBTU with the monthly profiles shown in Table V.

**Table V - Monthly Gas Price Profile**



**2. Oil Price Forecast** - Fuel price forecasts for 2012 for Heavy Oil (#6) and Light Oil (#2) were developed by Ventyx and are consistent with the oil price assumptions used in the SPP Cost Benefit Study for Future Markets. The annual average price for Heavy Oil was $10.00/MMBTU and the annual average price for Light Oil was $16.00/MMBTU. The monthly oil price forecast profile was developed using the monthly gas price pattern shown in Table V.

**3. ETI Peak Demand and Energy** – ETI peak demand for 2012 was 4696 MW and ETI projected native load Energy consumption was 25,522,776 MWhs. These values include Cooperative load within the ETI Area.[22]

**4. Hurdle Rates** – Unit Commitment hurdle rates between SPP and Entergy between SPP and all other markets were $25.00/MWh. The hurdle rate for dispatching purposes between SPP and Energy was $14.00/MWh. All other hurdle rates for dispatching purposes were set at $7.00/MWh.

**5. Transmission System Topology** – The SPP/Entergy transmission system topology for the Status-Quo Case and the ETI/SPP Integration Case is defined in Section 4. The set of monitored lines and contingency lists specified in PROMOD IV® for the purposes of Security Constrained Unit Commitment ("SCUC") and Security Constrained Economic Dispatch ("SCED") was agreed upon by SPP and ETI.

**6. Market Structure** – In all cases, the assumed market structure for SPP and Entergy is summarized as follows:

- Centralized Day-Ahead Unit Commitment;
- Centralized Security Constrained Economic Dispatch;
- Single Balancing Authority Area with Ancillary Service requirements determined at the Balancing Authority Area level;
- Locational Marginal Prices (LMPs) calculated at all generator and load nodes.

[22] Applicable shares of Plum Point and Independence generation resources were allocated to ETI in the PROMOD IV analysis to offset the Cooperative load in both the Status Quo Cases and ETI/SPP Integration Cases.

**7. RMR Requirements – Status Quo Cases** – In order to address the voltage-related RMR requirements in the Lewis Creek and Sabine areas, both Lewis Creek units and all five Sabine units were modeled as must-run for reliability for each hour at the following minimum output levels:

| Unit | Minimum Output - MW |
| --- | --- |
| Lewis Creek 1 | 62.5 |
| Lewis Creek 2 | 62.5 |
| Sabine 1 | 60 |
| Sabine 2 | 60 |
| Sabine 3 | 80 |
| Sabine 4 | 175 |
| Sabine 5 | 175 |

These must-run assumptions are consistent with historical Lewis Creek and Sabine operations.

**8. RMR Requirements – Integration Cases** – Consistent with preliminary stability analysis results[23] as provided in Appendix 6 as reviewed and agreed to by both SPP and ETI, voltage-related RMR requirements in the Sabine area can be reduced. These preliminary results indicate that only Sabine 5 would be required to be must-run, but both Lewis Creek units would continue to be required as must-run for reliability. However, to be conservative, SPP assumed that Sabine 5 would continue to be must-run and that Sabine 4 would be required to be must-run in the June through December time frame, with must-run modeling in the October through December timeframe being required to account for planned and forced outages associated with Sabine 5 and Cottonwood.

## 6.5. Production Cost Results

An Adjusted Production Cost ("APC") metric was used to measure ETI production cost savings in the analysis. This APC metric is consistent with the APC metric used in the SPP Cost Benefit Study for Future Markets and is defined as follows:

[23] Note that the stability analysis only included the addition of the Reliability Projects and is thus conservative with respect to reduction in Sabine RMR requirements. Inclusion of the Economic Projects in the stability analysis may further reduce the Sabine RMR requirements.

ETI Adjusted Production Costs = ETI Variable Generation Cost[24] + Purchases at ETI Load Hub Price – Sales at ETI Generation Hub Price.

The ETI Load Hub Price is equal to the load weighted average Locational Marginal Price ("LMP") of all ETI load buses and is calculated directly by PROMOD IV®. The ETI Generation Hub Price is equal to the generation weighted average LMP of all ETI generator buses and is calculated directly by PROMOD IV®. The APC is calculated on an hourly basis and then summed up by month and year. Table VI shows the projected annual 2012 ETI APC for each scenario studied.

**Table VI – Summary of ETI APC**

| Scenario | Gen - Gwhr | Gen - $MM | Gen Cost - $/Mwhr | Pur - Gwhr | Pur Cost - $MM | Pur Cost - $/Mwhr | Sales – Gwhr | Sales Rev - $MM | Sales Rev - $/Mwh | APC - $MM |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 21,192.8 | 2,114.276 | 99.76 | 4,367.1 | 341.583 | 78.22 | -590.5 | -74.317 | 125.85 | 2,381.542 |
| 2 | 18,379.8 | 1,765.241 | 96.04 | 6,661.9 | 545.103 | 81.82 | -72.3 | -9.196 | 127.22 | 2,301.147 |
| 3 | 20,105.2 | 1,920.946 | 95.54 | 4,997.2 | 419.402 | 83.93 | -133.1 | -16.648 | 125.10 | 2,323.700 |
| 4 | 17,465.4 | 1,811.222 | 103.70 | 7,570.2 | 638.708 | 84.37 | -66.3 | -9.340 | 140.95 | 2,440.590 |
| 5 | 16,186.8 | 1,607.328 | 99.30 | 8,785.7 | 801.118 | 91.18 | -3.2 | -0.480 | 151.15 | 2,407.965 |
| 6 | 22,129.5 | 1,412.030 | 63.81 | 3,710.9 | 193.546 | 52.16 | -871.0 | -65.172 | 74.82 | 1,540.404 |
| 7 | 18,436.5 | 1,147.623 | 62.25 | 6,614.4 | 355.837 | 53.80 | -81.5 | -6.775 | 83.10 | 1,496.685 |
| 8 | 19,897.4 | 1,231.822 | 61.91 | 5,168.5 | 284.439 | 55.03 | -96.5 | -7.841 | 81.25 | 1,508.420 |
| 9 | 18,500.5 | 1,228.345 | 66.40 | 6,539.3 | 366.827 | 56.10 | -70.4 | -6.039 | 85.79 | 1,589.133 |
| 10 | 16,623.3 | 1,073.696 | 64.59 | 8,346.9 | 487.484 | 58.40 | -0.8 | -0.083 | 100.40 | 1,561.097 |

**Scenario Definitions:**

1. Status-Quo Case – Cottonwood in EIC - $11.00 Gas
2. ETI/SPP Integration Case – Cottonwood in EIC with Weber-Richard Line- $11.00 Gas
3. ETI/SPP Integration Case – Cottonwood in EIC without Weber-Richard Line- $11.00 Gas
4. Status-Quo Case – Cottonwood in ERCOT - $11.00 Gas
5. ETI/SPP Integration Case – Cottonwood in ERCOT - $11.00 Gas
6. Status-Quo Case – Cottonwood in EIC - $7.00 Gas
7. ETI/SPP Integration Case – Cottonwood in EIC – with Weber-Richard Line - $7.00 Gas
8. ETI/SPP Integration Case – Cottonwood in EIC – without Weber-Richard Line - $7.00 Gas
9. Status-Quo Case – Cottonwood in ERCOT - $7.00 Gas
10. ETI/SPP Integration Case – Cottonwood in ERCOT - $7.00 Gas

Based on the APC results described above, SPP calculated the expected reduction in APC between the Status-Quo Cases and the Integration Cases. The ETI production cost benefit results are summarized in Table VII.

[24] Does not include Start-Up Costs.

**Table VII – Summary of ETI APC Benefits**

| Scenario | Gen - GWh | Gen - $MM | Gen Cost - $/MWh | Pur - GWh | Pur Cost - $MM | Pur Cost - $/MWh | Sales – GWh | Sales Rev - $MM | Sales Rev - $/MWh | Benefits $MM |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2,813.0 | 349.035 | 124.08 | -2,294.8 | -203.520 | 88.69 | -518.3 | -65.120 | 125.65 | 80.395 |
| 2 | 1,087.6 | 193.330 | 177.76 | -630.1 | -77.818 | 123.50 | -457.5 | -57.669 | 126.06 | 57.842 |
| 3 | 1,278.6 | 203.894 | 159.47 | -1,215.5 | -162.410 | 133.61 | -63.1 | -8.859 | 140.44 | 32.625 |
| 4 | 3,693.0 | 264.407 | 71.60 | -2,903.5 | -162.291 | 55.90 | -789.5 | -58.397 | 73.97 | 43.719 |
| 5 | 2,232.1 | 180.208 | 80.74 | -1,457.5 | -90.893 | 62.36 | -774.5 | -57.331 | 74.02 | 31.985 |
| 6 | 1,877.2 | 154.648 | 82.38 | -1,807.6 | -120.656 | 66.75 | -69.6 | -5.955 | 85.61 | 28.036 |

**Scenario Definitions:**

1. APC of Status-Quo Case – Cottonwood in EIC - $11.00 Gas less APC of ETI/SPP Integration Case – Cottonwood in EIC – **with** Weber-Richard Line - $11.00 Gas
2. APC of Status-Quo Case – Cottonwood in EIC - $11.00 Gas less APC of ETI/SPP Integration Case – Cottonwood in EIC – **without** Weber-Richard Line - $11.00 Gas
3. APC of Status-Quo Case – Cottonwood in ERCOT - $11.00 Gas less APC of ETI/SPP Integration Case – Cottonwood in ERCOT - $11.00 Gas
4. APC of Status-Quo Case – Cottonwood in EIC - $7.00 Gas less APC of ETI/SPP Integration Case – Cottonwood in EIC – **with** Weber-Richard Line - $7.00 Gas
5. APC of Status-Quo Case – Cottonwood in EIC - $7.00 Gas less APC of ETI/SPP Integration Case – Cottonwood in EIC – **without** Weber-Richard Line - $7.00 Gas
6. APC of Status-Quo Case – Cottonwood in ERCOT - $7.00 Gas less APC of ETI/SPP Integration Case – Cottonwood in ERCOT - $7.00 Gas

Under Scenario 1, ETI internal generation was reduced by 2,813.0 GWh and was replaced by more economic ETI purchases[25] (2,294.8 GWh) and a reduction in ETI sales[26] (518.3 GWh). The APC ETI benefits of $80.395 Million are then equal to the reduction in ETI generation cost ($349.035 Million) less the cost of purchases ($203.52 Million) less the loss in sales revenue ($65.12 Million).

Under Scenario 2, ETI internal generation was reduced by 1,087.6 GWh and was replaced by more economic ETI purchases (630.1 GWh) and a reduction in ETI sales (457.5 GWh). The ETI benefits of $57.842 Million are then equal to the reduction in ETI generation cost ($193.330 Million) less the cost of purchases ($77.818 Million) less the loss in sales revenue ($57.669 Million).

[25] Purchases volume is a combination of purchases from internal SPP market and purchases external to SPP.

[26] Sales volume is a combination of ETI internal sales to SPP and sales external to SPP

Under Scenario 3, ETI internal generation was reduced by 1,278.6 GWh and was replaced by more economic ETI purchases (1,215.5 GWh) and a reduction in ETI sales (63.1 GWh). The ETI benefits of $32.625 Million are then equal to the reduction in ETI generation cost ($203.894 Million) less the cost of purchases ($162.410 Million) less the loss in sales revenue ($8.859 Million).

Under Scenario 4, ETI internal generation was reduced by 3,693.0 GWh and was replaced by more economic ETI purchases (2,903.5 GWh) and a reduction in ETI sales (789.5 GWh). The ETI benefits of $43.719 Million are then equal to the reduction in ETI generation cost ($264.407 Million) less the cost of purchases ($162.291 Million) less the loss in sales revenue ($58.397 Million).

Under Scenario 5, ETI internal generation was reduced by 2,232.1 GWh and was replaced by more economic ETI purchases (1,457.5 GWh) and a reduction in ETI sales (774.5 GWh). The ETI benefits of $31.985 Million are then equal to the reduction in ETI generation cost ($180.208 Million) less the cost of purchases ($90.893 Million) less the loss in sales revenue ($57.331 Million).

Under Scenario 6, ETI internal generation was reduced by 1,877.2 GWh and was replaced by more economic ETI purchases (1,807.6 GWh) and a reduction in ETI sales (69.6 GWh). The ETI benefits of $28.036 Million are then equal to the reduction in ETI generation cost ($154.648 Million) less the cost of purchases ($120.656 Million) less the loss in sales revenue ($5.955 Million).

### 6.6. Summary

For the Cottonwood in EIC assumption with the Weber-Richard 500 kV line and $11.00 gas price assumption, the total reduction in ETI APC resulting from the integration of ETI into SPP is estimated at $80.4 Million assuming:

- All Sabine units are must-run at minimum output in the Status Quo Case;
- Only Sabine 4 is must-run in Jun-Dec timeframe and Sabine 5 is must-run in Jan-Dec timeframe in ETI/SPP Integrated Case and all other Sabine units are modeled as economic;

- All transmission upgrade projects with in-service dates in the 2012 timeframe that were approved and budgeted by Entergy and SPP for construction and certain Entergy proposed transmission upgrade projects were included in both the Status-Quo Case and the ETI/SPP Integration Case;
- All Reliability Projects were included in the ETI/SPP Integration Case; and
- Both the Mt. Olive to Hartburg upgrade and the new Weber to Richard 500 kV line were included in the ETI/SPP Integration Case.

For the Cottonwood in EIC assumption without the Weber-Richard line and $11.00 gas price assumption, the total reduction in ETI APC resulting from the integration of ETI into SPP is estimated at $57.8 Million under the same assumptions as the Cottonwood in EIC with the Weber-Richard 500 kV line and $11.00 gas scenario except that the Weber-Richard line was not included.

For the Cottonwood in ERCOT assumption and $11.00 gas price assumption, the total reduction in ETI APC resulting from the integration of ETI into SPP is estimated at $32.6 Million assuming:

- All Sabine units are must-run at minimum output in the Status Quo Case;
- Only Sabine 4 is must-run in Jun-Dec timeframe and Sabine 5 is must-run in Jan-Dec timeframe in ETI/SPP Integrated Case and all other Sabine units are modeled as economic;
- All transmission upgrade projects with in-service dates in the 2012 timeframe that were approved and budgeted by Entergy and SPP for construction and certain Entergy proposed transmission upgrade projects were included in both the Status-Quo Case and the ETI/SPP Integration Case;
- All Reliability Projects were included in the ETI/SPP Integration Case;
- The new Weber to Richard 500 kV line was included in the Status Quo Case; and
- Both the Mt. Olive to Hartburg upgrade and the new Weber to Richard 500 kV line were included in the ETI/SPP Integration Case.

For the Cottonwood in EIC with the Weber-Richard line assumption and $7.00 gas price assumption, the total reduction in ETI APC resulting from the integration of ETI into SPP is estimated at $43.7 Million under the same assumptions as the Cottonwood in EIC, $11.00 gas scenario.

For the Cottonwood in EIC assumption without the Weber-Richard line and $7.00 gas price assumption, the total reduction in ETI APC resulting from the integration of ETI into SPP is estimated at $32.0 Million under the same assumptions as the Cottonwood in EIC with the Weber-Richard 500 kV line and $7.00 gas scenario except that the Weber-Richard line was not included.

For the Cottonwood in ERCOT assumption and $7.00 gas price assumption, the total reduction in ETI APC resulting from the integration of ETI into SPP is estimated at $28.0 Million under the same assumptions as the Cottonwood in ERCOT, $11.00 gas scenario.

## 7. Retail Open Access Study

SPP was tasked with developing a high-level cost estimate for implementing Retail Open Access ("ROA") in SPP with the integration of ETI. This section discusses the processes and assumptions utilized in developing the cost estimates and implementation objectives.

### 7.1. Process

SPP reviewed its current processes and procedures to determine what processes and systems would need to be changed in order to integrate ETI into SPP and enable ROA for ETI. SPP worked with internal staff, ERCOT Staff, and stakeholders to identify and compare processes currently utilized by ERCOT to support ROA, and to determine which existing processes could be leveraged to implement ROA for ETI as part of SPP and which processes would be need to revised or created to implement ROA for ETI in SPP. To accomplish this, SPP representatives worked with ERCOT Staff to develop a list of functional areas to be analyzed. Assumptions and changes were communicated to the stakeholders through stakeholder meetings. A comparison summary table is included in Appendix 7.

#### 7.1.1 Customer Registration

Should ETI join SPP, ERCOT would continue to manage the customer registration process in the same manner it does today, which includes loading Electric Service Identifiers ("ESI IDs") for the ETI area into the registration database, assisting with the retail market testing, qualifying Transmission Distribution Service Providers ("TDSPs") and Retail Energy Providers ("REPs") for retail transactions, managing the dispute process for data in the retail customer registration system, and validating meter data. SPP would use its existing processes and procedures to register each REP (including ETI's affiliated REP) as a Transmission Customer ("TC") within SPP.

As part of the initial implementation, ERCOT would work with ETI to obtain registration data and load that data into their systems. ERCOT would coordinate with ETI, SPP and stakeholders to create load profiles for the ETI area. This process of setting the ETI area up in ERCOT's customer registration system is very similar whether ETI becomes part of ERCOT or SPP. Additionally, ERCOT would regularly provide an ESI ID Service History and Usage Extract (aka "SCR727" extract) for ETI to validate the information in ERCOT's system. Once the initial SCR727 data is loaded and load profiles are established, ETI will receive daily SCR727 extracts.

### 7.1.2 Transmission Access and Scheduling

In the ERCOT region, all entities serving load (such as REPs) or providing power must be represented by Qualified Scheduling Entities ("QSEs") for scheduling and wholesale settlement purposes. These QSEs must submit energy and load schedules and may also submit ancillary service bids. These QSEs settle with ERCOT and pass various ERCOT charges on to their clients through bilateral agreements to which ERCOT is not a party. REPs operating in the ERCOT region do not have to request transmission service as all load-serving entities are allowed access to the transmission system.

As participants in the SPP region, REPs would be considered TCs. Each TC with load must request transmission service from SPP, designating resources to serve its load. SPP studies each transmission service request and either approves the request or identifies transmission upgrades needed to support the request. Once an entity has transmission access as a TC, it must also register as a Market Participant with SPP in order to schedule and settle with SPP. If a REP does not wish to interact directly with SPP for scheduling and settlement purposes, it may designate an agent to act on its behalf (like a QSE in ERCOT[27]). Registering with SPP allows an entity to do business with SPP on the Open Access Same Time Information System ("OASIS)" and participate in SPP markets.

[27] A REP operating in the SPP area would not need a QSE in order to interact with ERCOT for customer registration purposes. QSEs are involved in ERCOT scheduling and whole settlement functions only – processes which are handled differently in SPP.

### 7.1.3 Data Aggregation

Using data obtained from its customer registration system, ERCOT aggregates the data, applies loss calculations and loads the aggregated data into its wholesale settlement system to enable wholesale settlement. Because ERCOT's system is not currently designed to export data to another ISO, SPP and ERCOT identified a mechanism to enable SPP to have access to the data via existing processes. As mentioned above, ETI would receive SCR727 extract data on a regular basis. This extract conveniently contains all the usage data SPP would need to settle its markets. ETI would be able to provide SPP with access to this extract on an on-going basis via a digital certificate assigned to SPP. Through this arrangement, SPP would always have access to the most current data in ERCOT's registration system. SPP would then be able to aggregate the data and load it into its settlement system. Aggregating the data and applying appropriate loss calculations would require a new data aggregation module to be built within SPP's settlement system. This module would convert, aggregate and load the needed data into SPP's staging system for validation. Once validated, the data will be loaded into SPP's production system for billing and settlements.

### 7.1.4 Settlement and Invoicing

Both ERCOT and SPP have complex settlement systems for the allocation of various charges to various Market Participants. ERCOT and SPP do not have identical timelines for settlement and invoicing; however, SPP expects that SPP's settlement timelines will be able to accommodate the timing of the data received via the SCR727 extract.

ERCOT currently invoices QSEs for wholesale market charges and ERCOT fees, and each TDSP in the ERCOT region invoices REPs active in its territory for charges pursuant to its tariff. ERCOT also currently charges a non-ERCOT REP an annual fee of $1.15 per ESI ID. Although there have been discussions regarding the discontinuance of this fee due to complete depreciation of ERCOT's customer registration system, SPP used the $1.15 per ESI ID fee as a placeholder for estimating approximate costs for using the ERCOT customer registration system to serve a non-ERCOT area. If this particular fee is eliminated in the future, SPP expects that it would work with ERCOT to negotiate a new fee structure with comparable total cost.

For balancing energy and associated fees, SPP would invoice the TCs or their agents. Any other administrative fees would be allocated to the REPs through SPP's settlement processes.

### 7.1.5 Disputes

ERCOT already provides a robust dispute system[28] for any issues regarding the data contained in its customer registration system. Therefore, SPP expects that any dispute regarding the data in ERCOT's systems would be handled through ERCOT's existing system. Disputes regarding wholesale settlement or invoicing would generally be handled by SPP; however, any settlement dispute which results from claimed inaccuracies in the underlying data provided from ERCOT's registration system would not constitute a valid settlement dispute with SPP and those data issues would have to be resolved with ERCOT.

## 7.2. Cost Estimates

### 7.2.1 Assumptions

The following assumptions were used in developing the cost estimates.

ERCOT will perform or assist with the following activities:

- Continue the management of the registration database for ETI ESI IDs' in Texas;
- Assist ETI in submitting appropriate transactions to load the ESI ID's into their database approximately 425,000 ESI IDs;
- Assist ETI affiliated REP to submit appropriate transactions to move-in ~ 425,000 ESI IDs;
- Submit appropriate initial meter reads for the ESI IDs;
- Assist ETI and REPs in completion of Retail Market Testing;
- Produce the initial SCR727 Service History and Usage Extract load for ETI (to also be provided to SPP);
- Produce daily SCR727 extracts for ETI (to also be provided to SPP);

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[28] Known as "MarkeTrak."

- Work with ETI, SPP and stakeholders via the Profiling Working Group for to create Weather Zone and Profile Tree approvals;
- Assist ETI with Profile ID assignments;
- Assist ETI with Load Research Sampling and;
- Support the retail activities in the ETI territory of Texas.

SPP will perform the following activities:

- Register all REPs as TCs for transmission access and Market Participants for scheduling, settlement, and billing;
- Support interaction with REPs on an on-going basis;
- Develop aggregation processes and programs to validate and load initial meter reads for ESI IDS;
- Develop ongoing processes to validate, load, and aggregate data from the SCR727 extract and;
- Coordinate with ERCOT and ETI for load profiling and SCR727 extract processes.

### 7.2.2 Cost Estimates

The following estimates were developed with input from SPP Staff, Areva and ERCOT. SPP developed a cost range for each component associated with implementation. In addition, SPP developed an estimate of ongoing maintenance costs associated with enabling ROA in SPP. Labor rates were based on 2009 Cost Benefit Task Force ("CBTF") [29] rates and include a blend of SPP resources and consultants.

**Implementation estimates**

| Item | Low | High |
|---|---|---|
| Registration and Set-up Resources | $ 520,000 | $ 850,000 |
| Settlement System Changes | $1,275,000 | $3,000,000 |
| Miscellaneous Hardware | $ 100,000 | $ 200,000 |
| ERCOT Startup Costs to Implement ROA for ETI | $ 437,000 | $ 740,000 |
| **Total ROA Implementation Estimates** | **$2,332,000** | **$4,790,000** |

The registration and set-up components include the labor and costs associated with the creation of accounts in the SPP customer account management, credit and associated systems. The settlement system component is comprised of: 1) requirements gathering and 2) associated implementation costs of an aggregation module that integrates with the current settlement system. Miscellaneous hardware costs include storage and estimated Information Technology ("IT") costs. The ERCOT startup costs were developed from information contained in Appendix 9 of ERCOT's Phase II Study and one-time development costs provided by ERCOT to SPP in 2008. ERCOT's high level impact analysis is included as Appendix 8.

[29] An SPP stakeholder group.

**Annual Maintenance Estimates**

| Item | Low | High |
|---|---|---|
| Staffing | $ 375,000 | $ 560,000 |
| Settlement System Fees | $ 150,000 | $ 150,000 |
| Miscellaneous Hardware | $ 40,000 | $ 70,000 |
| ERCOT Fees (est.) | $ 50,000 | $ 480,000 |
| **Total Annual Maintenance Estimates** | **$ 615,000** | **$1,260,000** |

For the estimated maintenance costs, staffing rates were based on the 2009 CBTF rates. The staffing estimate assumes that SPP would need to hire two to five new Full Time Equivalents to support the additional settlement systems processes and related work along with the related IT functions. Estimated cost of the settlement system additions were supplied by the potential vendor. Miscellaneous Hardware costs are for the storage and associated items that would be required by SPP IT Staff. The ERCOT fee estimates were based on the assumptions and high level impact analysis that was provided by ERCOT.

## 8. Benefit to Cost Results

### 8.1 Benefit to Cost Analysis Results

The Benefit/Cost Analysis compares the benefits to ETI associated with integration into SPP to the associated costs to ETI, as calculated in accordance with the study tracks defined under Section 2 of this Report, through calculation of an ETI Benefit-to-Cost Ratio ("BC Ratio"). ETI Benefit-to-Cost Ratio is calculated for all scenarios, as: ([ETI production cost savings / 0.18[30]] / [Reliability Project capital costs + Economic Project capital costs + ROA implementation capital costs]). A BC Ratio of less than 1.0 indicates a net negative benefit and a BC Ratio of greater than 1.0 indicates a net positive benefit. A BC Ratio equal to 1.0 indicates a break-even situation. Based on this calculation, the ETI BC Ratios for each scenario are summarized in Table I.

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[30] Consistent with the Phase II Study, in order to directly compare the production cost savings to the cost of the Reliability Projects, Economic Projects and ROA implementation for cost/benefit calculation purposes, the production cost savings is divided by the assumed annual carrying charge rate. SPP uses an 18% carrying charge rate assumption in its Balanced Portfolio analysis process.

For the Cottonwood in EIC assumption, SPP calculated a range of potential ETI net benefits reflecting the assumption regarding inclusion or exclusion of the new Weber-Richard 500 kV line. For the $11.00 gas price assumption, ETI net benefits range from a low of $97.8 Million if the line is included to a high of $201.5 Million if the line is excluded. For the $7.00 gas price assumption, ETI net benefits range from a low of $(105.9) Million if the line is included to a high of $57.9 Million if the line is excluded, thus indicating a potential net negative benefit to ETI under the $7.00 gas price assuming the new Weber-Richard line is included. However, for all BC Ratio calculations, SPP has used conservative assumptions by including the entire cost of the Economic Projects under the cost side of the equation. Further analysis and discussion is required regarding the expected cost allocation of Economic Project costs which may conclude that some of the Economic Project costs should be borne by parties other than ETI, which could result in a net positive benefit to ETI assuming inclusion of the Weber-Richard 500 kV line under the $7.00 gas price assumption.

Under both the $11.00 gas price and $7.00 gas price assumption for the case where Cottonwood moves into ERCOT, net benefits to ETI remain positive, ranging from $36 Million for the $7.00 gas price assumption to $61.4 Million for the $11.00 gas price assumption.

**Table I – ETI Benefit/Cost Analysis Summary**

| Scenario | Production Cost Savings $MM | Equivalent Capital Cost $MM | Reliability Project Costs $MM | Economic Project Costs $MM | ROA Costs $MM | Net Benefit $MM | BC Ratio |
|---|---|---|---|---|---|---|---|
| **1** | 80.4 | 446.6 | 105 | 239 | 4.8 | 97.8 | 1.28 |
| **2** | 43.7 | 242.9 | 105 | 239 | 4.8 | (105.9) | 0.70 |
| **1A** | 57.8 | 321.3 | 105 | 10 | 4.8 | 201.5 | 2.68 |
| **2A** | 32.0 | 177.7 | 105 | 10 | 4.8 | 57.9 | 1.48 |
| **3** | 32.6 | 181.2 | 105 | 10 | 4.8 | 61.4 | 1.51 |
| **4** | 28.0 | 155.8 | 105 | 10 | 4.8 | 36.0 | 1.30 |

Scenario 1 - Cottonwood in EIC - $11.00 Gas – With Weber-Richard 500 kV line
Scenario 2 - Cottonwood in EIC - $7.00 Gas – With Weber-Richard 500 kV line
Scenario 1A - Cottonwood in EIC - $11.00 Gas – Without Weber-Richard 500 kV line
Scenario 2A - Cottonwood in EIC - $7.00 Gas – Without Weber-Richard 500 kV line
Scenario 3 - Cottonwood in ERCOT - $11.00 Gas
Scenario 4 - Cottonwood in ERCOT - $7.00 Gas

# 9. APPENDIXES

## 9.1. Appendix 1 - List of Entergy Proposed Projects

## 9.2. Appendix 2 - Topology Map

## 9.3. Appendix 3 - Market Power Study Report

## 9.4. Appendix 4 - Entergy Construction Plan

## 9.5. Appendix 5 - STEP Plan

## 9.6. Appendix 6 - SPP-Entergy SPP_ETI Integration Summary Stability Report

## 9.7. Appendix 7 - ROA Functionality Chart

## 9.8. Appendix 8 - ERCOT High Level Impact Analysis

## Appendix 1- List of Entergy Proposed Projects

| Year Proposed | Entergy Affiliation | Description |
|---|---|---|
| 2008 | EAI | Upgrade to Rison Risers |
| **2008** | **ETI** | **Reconductor Newton Bulk**** |
| 2009 | EAI | Update Colonel Glenn 2012 Loa |
| 2009 | EAI | Add Gillett Cap Bank |
| 2009 | EGSI-LA | New Jefferson-Neser 69kV |
| 2009 | ELL-S | Upgrade S WESCO |
| 2009 | EMI | HornLake 230/161kV Xfmr and HornLake-Allen line |
| 2009 | EMI | Liberty-Gillsburg Uprate Line To 100MVA |
| 2009 | ETI | Beaumont 69kV Improvement Plan |
| **2009** | **ETI** | **Close College Station 138kV NO Switch**** |
| 2010 | EAI | Upgrade SMEPA |
| 2010 | EGSI-LA | Upgrade Alchem-Monochem 138kV |
| 2010 | EGSI-LA | Upgrade Lawtag-Jennings 69kV |
| 2010 | ELL-N | Install Arcadia 36MVAr Cap Bank |
| 2010 | ELL-S_SE_LA | SE LA Coastal Improvement Phase 2 |
| 2010 | ELL-S_SE_LA | SE LA Coastal Improvement Phase 3 |
| 2010 | EMI | ChurchRd Add New Line and Sub |
| 2010 | ETI | Install Johnstown 138kV |
| **2010** | **ETI** | **Upgrade Porter Tamina Cedar Hill 138kV**** |
| 2011 | EAI | Upgrade Cabo |
| 2011 | EAI | Update Crawford 2012 Load |
| 2011 | EAI_ELL | Sarepta + Additions |
| 2011 | EAI | Upgrade Grandview |
| 2011 | EAI | Update Hamilton 2012 Load |
| 2011 | EAI | Update HWY64 2012 Load |
| 2011 | EMI | Upgrade RayBraswell-Byram Line |
| 2011 | ETI | Install Merlin 138kV |
| 2012 | ELL-S_EGSI-LA | UpgradeColy-Hammond 230kV |
| 2012 | EMI | Madison Ridgeland Reliability |
| 2012 | EMI | Tillatoba-SouthGrenada Line and Auto |
| **2012** | **ETI** | **Western Region Reliability Improvement Phase 3 Final**** |

**Proposed Projects included in Status Quo Cases and ETI/SPP Integration Cases.

## Appendix 2: Topology Map

This document is classified as Critical Energy Infrastructure Information ("CEII") by the Federal Energy Regulatory Commission ("FERC") and will be released upon execution of the appropriate Non-Disclosure Agreement with SPP.

## Appendix 3: Market Power Study Report

# MARKET POWER STUDY
# OF
# ENTERGY TEXAS INTEGRATION INTO THE SOUTHWEST POWER POOL

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POTOMAC ECONOMICS, LTD.

December 2008

CONFIDENTIAL MATERIAL REDACTED

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# I. Introduction and Summary

Potomac Economics has been engaged to perform an evaluation of market power related to Entergy Texas, Inc. (ETI) joining the Southwest Power Pool (SPP) and to identify mitigation options that would address any market power issues found.

This study is designed to address requirements of the Public Utility Regulatory Act (PURA) as modified by Texas Senate Bill 7.[1] There are two relevant requirements in this case. First, PURA establishes a maximum market share threshold of 20 percent for any area to be defined as a Qualified Power Region (QPR).[2] In other words, a region satisfies this test to be a QPR if no suppliers have a market share greater than 20 percent. Our analysis confirms that this test is satisfied for the combined SPP/ETI Area.[3]

Second, PURA requires that the analysis include an assessment of import capability for QPRs that are not entirely within Texas:

> In determining whether a power region not entirely within the state meets the requirements of this section, the commission shall consider the extent to which the available transmission facilities limit the delivery of electricity from generators located outside the state to areas of the power region within the state.[4]

However, PURA and subsequent Public Utility Commission of Texas (PUCT) precedent do not provide specific guidance or requirements for the analysis necessary to satisfy this section. Hence, we interpret this section as a requirement to evaluate local market power in transmission-constrained areas in the portions of the ETI service area ("the ETI Area"). Because transmission constraints can isolate areas with a relatively small number of potential suppliers, it is the local market power analysis that is most likely to indicate potential competitive concerns that may require some form of market power mitigation.

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1 Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §39 (PURA).

2 PURA §39.152(a)(3).

3 Throughout this report the term "ETI Area" is used to describe the area of Texas currently served by Entergy Texas, Inc. (ETI).

4 PURA §39.152(b).

We use a number of market power indicators in this analysis. These indicators include several measures of how concentrated the ownership of supply is in the constrained areas, as well as a determination of whether the largest supplier's resources are needed to meet the demand in the area (i.e., whether the supplier is "pivotal"). Finally, because there are significant transmission constraints that bind into and within the ETI Area, we define two geographic markets for these analyses:

- The entire ETI Area; and
- The Western Subregion within the ETI Area (which is defined as the load and resources west of the Jacinto and Cypress substations).

Our analysis of the local market power issues in the ETI Area indicate limited potential competitive concerns in the ETI Area or Western Subregion. The market concentration results indicate that the market in the ETI Area will support workable competition, although the concentrations are in the highly-concentrated range. Requiring ETI to sell a portion of its capacity in the ETI Area via capacity auctions as described in PURA would substantially reduce the market concentration in the area.

With regard to the pivotal supplier analysis, most scenarios show that ETI will not be pivotal (including all analyses of the Western Subregion ). In two cases where we find ETI to be pivotal, we also find that there are a number of factors that significantly ease our competitive concerns. First, ETI has a number of reliability-must-run (RMR) obligations in the area that compel its generation to run to support the reliability of the system. These obligations would prevent ETI from threatening to withhold supply.

Second, the concern in this study is whether ETI could raise prices to retail customers in the region. In scenarios that show ETI as pivotal, it is pivotal over a relatively small portion of the load. Hence, ETI would have to withhold most of its resources to raise prices to a small portion of load. Further, the magnitude of that price increase would be limited by ETI's obligations as a provider-of-last-resort (POLR). Although the specifics of the POLR pricing provisions that would apply to ETI are unknown, it is highly unlikely that they would allow a price increase large enough to make withholding profitable in this case.

Third, in the cases where ETI is pivotal, it is only in a small number of hours. The pivotal supplier analysis uses the load forecast for the annual peak of the year. In general, the load declines sharply from the annual peak hour to other hours, which limits the extent to which ETI is pivotal. In other words, ETI's resources would only be needed to serve a portion of the load when load levels are close to the annual peak.

Finally, as a Regional Transmission Organization (RTO), SPP will have a market monitor and market power mitigation measures necessary to address concerns in the region. Given the vast quantities of withholding that would be necessary to exploit ETI's pivotal supplier status, its conduct would not go unnoticed by the market monitor or the Federal Energy Regulatory Commission (FERC).

Hence, we find that market power mitigation measures are not necessary to address competitive issues in this case. However, if policymakers desire additional assurance that the market will perform competitively, implementing a 15 percent capacity auction as called for in PURA would lower concentration levels and reduce the extent to which ETI is pivotal. Unless additional transmission capacity can be built that produce net benefits to the region, capacity auctions are the most cost-effective form of market power mitigation.

## II. Market Shares in the Combined SPP/ETI Region

### A. Requirements of PURA

As described in the introduction, this study is designed to address the requirements of PURA. There are two relevant requirements in this case. First, PURA establishes a maximum market share threshold for any area to be defined as a Qualified Power Region (QPR):

> QUALIFYING POWER REGIONS. (a) The commission shall certify a power region if:
> (1) a sufficient number of interconnected utilities in the power region fall under the operational control of an independent organization as described by Section 39.151;
> (2) the power region has a generally applicable tariff that guarantees open and nondiscriminatory access for all users to transmission and distribution facilities in the power region as provided by Section 39.203; and
> (3) no person owns and controls more than 20 percent of the installed generation capacity located in or capable of delivering electricity to a power region, as determined according to Section 39.154.[5]

Our market share analysis addresses part (3) of this requirement. Market share analyses offer the simplest, most basic characterization of potential market power. The wholesale market share screen measures whether a seller has a dominant position in the market based on the number of megawatts of installed capacity owned or controlled by the seller as compared to the installed capacity of the entire relevant market.

To calculate the market shares, we use the maximum capacity ratings from the SPP summer 2012 power flow base case. For simplicity, each supplier's total represents a simple "steel in ground" amount.[6] Affiliated companies' generation was aggregated to the parent/holding company. The totals do not reflect contract sales or purchases, transmission limitations, or other complications.[7] The analysis is also conservative because it does not reflect the import

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5 PURA §39.152.

6 The one exception to this is the Tenaska Gateway plant. Gateway is switchable between the Eastern Interconnect and ERCOT, but can only deliver 195 MW of its 1,132 MW into SPP.

7 PUCT Subst. R. §25.401 provides detailed guidance on calculating the installed generation shares. Our analysis does not address four points in the detailed guidelines. Our calculation did not consider: (1) affiliated generators located outside of the region; (2) generators located on the boundary between regions; (3) grandfathered generating capacity located within ozone non-attainment areas; and (4) transmission import capability into the region. The most significant factor in this analysis would be the inclusion of some additional supply owned by ETI's affiliates outside of the SPP/ETI Region. However, ETI's market share would remain

(Footnote is continued on the next page.)

capability from outside the SPP/ETI Area. Hence, capacity shares are understated because imported supply is not included. Table 1 shows our analysis:

**Table 1: Market Shares in the SPP/ETI Area**

| Supplier | Capacity | Share of Combined Regions |
|---|---|---|
| American Electric Power Co., Inc. | 9,754 | 18.5% |
| Westar Energy Inc. | 6,568 | 12.4% |
| OGE Energy Corp. | 5,812 | 11.0% |
| Xcel Energy, Inc. | 4,195 | 7.9% |
| Great Plains Energy Corp. | 4,039 | 7.6% |
| Tenaska, Inc. | 2,348 | 4.4% |
| ***ETI*** | ***2,300*** | ***4.4%*** |
| Calpine Corp. | 1,352 | 2.6% |
| Western Farmers Electric Coop | 1,292 | 2.4% |
| Empire District Electric Co. | 1,263 | 2.4% |
| Kelson Energy | 1,250 | 2.4% |
| Bechtel Group, Inc. | 1,200 | 2.3% |
| All others less than 2% | 11,449 | 21.7% |
| Total | 52,823 | 100.0% |

This analysis shows that ETI has a capacity share of 4.4 percent and that no supplier has a market share greater than 20 percent. Hence, the market share QPR requirement is satisfied for the combined SPP/ETI Area.

well below 20 percent even if this capacity were included (to the extent import capability would allow it to be delivered into the area). Given the total supply in the region, the other factors would also not likely cause the 20 percent market share threshold to be violated.

# III. Local Market Power Analysis for the ETI Area

## A. Requirements of PURA and Market Power Metrics

PURA requires that the analysis include an assessment of import capability for QPRs that are not entirely within Texas:

> In determining whether a power region not entirely within the state meets the requirements of this section, the commission shall consider the extent to which the available transmission facilities limit the delivery of electricity from generators located outside the state to areas of the power region within the state.[8]

PURA and subsequent PUCT precedent do not provide specific guidance or requirements for the analysis necessary to satisfy this section. Hence, we interpret this section as a requirement to evaluate local market power in transmission-constrained areas in the ETI Area. To produce a robust evaluation of potential local market power, we analyze two measures of market power in both the ETI Area and the Western Subregion. For each measure, we conduct multiple scenarios that address alternative assumptions regarding obligations to serve load and the participation of a key supplier in the ETI Area. These alternatives are described in the following subsections.

### 1. Measures of Market Power

To evaluate the competitiveness of the market in both the ETI Area and Western Subregion, we perform the following two analyses.

*Market Concentration Analysis*: A common measure of market concentration used by economists is the Herfindahl-Hirschman Index (HHI). The HHI is a standard measure of market concentration calculated by summing the square of each supplier's market share. The index ranges from 0 to 10,000, increasing as suppliers' market shares increase and as the number of suppliers serving the market falls. The antitrust agencies generally characterize markets with HHIs greater than 1,800 as highly concentrated.[9] Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the

8 PURA §39.152(b)

9 The DOJ and FTC evaluate the *change* in HHI as part of standard merger analysis. However, this is only a preliminary analysis that would typically be followed by a more rigorous evaluation of the likely price effects of the merger.

more likely it is that firms would be able to extract excess profits from the market. Due to the prevalence of excess capacity in most hours and other factors that tend to mitigate market power in electricity markets, it is reasonable to conclude that markets with HHIs less than 2,500 are likely to be workably competitive. This is consistent with the range that Mr. Schnitzer established as a market power mitigation target in his prior study of the competitive issues associated with integrating the ETI Area into SPP.[10]

The market share assessment and HHI statistics provide only general indicators of market concentration in electric power markets, not definitive measures of market power.[11] The usefulness of these statistics is limited by the fact that they reflect only the supply-side, and ignore demand-side factors affecting competition. Also, these statistics are relatively static in orientation, which limits their value for characterizing the constantly changing balance of resources and load affecting market power in electric markets. Since electricity cannot be stored economically in large scale, production must match demand on a real-time basis. When demand rises, a larger share of generation is used to satisfy the demand. This means there are fewer alternative resources remaining that could increase output to counteract the actions of a supplier seeking to withhold resources. Hence, markets with higher resource margins tend to be more competitive, but both the market share and HHI statistics neglect this aspect of the market. Pivotal supplier analysis, discussed next, addresses this shortcoming.

*Pivotal Supplier Analysis*: A more reliable means to evaluate the competitiveness of electricity markets and recognize the dynamic nature of market power in these markets is to identify when one or more suppliers are "pivotal". A supplier is pivotal when the output of some of its resources is needed to meet demand in the market. A pivotal supplier has the ability to unilaterally raise the market prices by withholding its supply. However, a pivotal supplier will only have market power if it has the *incentive* to engage in this conduct. In other words, it must be profitable for the supplier to withhold its supply.

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10 Report of Michael Schnitzer, Entergy Gulf States, Inc.'s Transition to Competition Plan at para. 85 (December 29, 2006)

11 For example, see Severin Borenstein, James B. Bushnell, and Christopher R. Knittel, "Market Power in Electricity Markets: Beyond Concentration Measures," *Energy Journal* 20(4), 1999, pp. 65-88.

To determine whether a particular supplier is pivotal, we remove the resources of this supplier from the total available resources and compare this to the total demand for energy and reserves. Total available resources include those located in the market area as well as those that can be supplied to the market through import capability. If internal resources and import capability (excluding those of the supplier in question) are sufficient to satisfy the demand, the supplier is not pivotal. Alternatively, if the internal resources and import capability without the supplier are not sufficient to satisfy the demand, the supplier is pivotal.

### 2. Data Sources

The data for our analysis comes primarily from the SPP summer 2012 power flow base case. This includes the maximum physical capability of each generating unit as well as the maximum transmission capacity between the ETI Area and the rest of SPP. For jointly-owned units, ownership shares were identified using data provided by Entergy, SPP, and Platts. Data on long-term firm transactions was provided by Entergy.

### 3. Scenarios

We evaluate a range of concentration and pivotal supplier scenarios in order to reflect two important aspects of the market. First, we incorporate certain assumptions about suppliers' load obligation in our analysis. Second, we consider the uncertain status of the Cottonwood facility owned by Kelson Energy. This facility has initiated a process to disconnect from the Eastern Interconnect and interconnect to ERCOT.

*Load Obligations*

The obligation to serve load, whether by long-term contract or regulation, has a significant effect on this analysis. Although this study is intended to reflect full retail competition, we recognize that load obligations will likely exist at some level. In most areas where retail competition has been introduced, a limited portion of the native load has switched to alternative suppliers. Additionally, utilities in Texas may be required to serve as the provider-of-last-resort for retail customers in their area. This obligation includes pricing for such service that is regulated by the PUCT.

These load obligations have a significant effect on market power findings because a supplier will not have an incentive to withhold resources it needs to serve its load. Resources that cannot be withheld should be accounted for in the analysis of a firm's market power. The changing load obligations under retail competition complicate assumptions regarding market concentration and pivotal supplier calculations.

We consider three scenarios to reflect alternative assumptions regarding the portion of existing load suppliers will be obligated to serve. We include a zero-percent load obligation case, a 50-percent load obligation case, and 100-percent load obligation case. A zero-percent load obligation case reflects full retail competition with no obligation to serve current retail customers. The *installed capacity* measure described below is used for this case because it includes no offset for load obligations.

When load obligations are non-zero (i.e., in the 50-percent and 100-percent load obligation cases), then the market share and pivotal supplier calculations are based on an *uncommitted capacity* analysis. Uncommitted capacity is calculated based on the installed capacity minus the load obligations of each supplier. This metric better addresses how obligations to serve load at a fixed price affect a supplier's incentives to exercise market power.

The 100-percent load obligation case assumes no retail load switching. The 50-percent load obligation case reflects the load switching experience in ERCOT where we understand that approximately 40 percent of load has switched under the retail access program.

*Cottonwood Plant*

The second aspect of the market supply that we include in the market concentration and pivotal supplier calculations involves the Cottonwood generating facility owned by Kelson Energy. This facility is currently physically connected to the ETI Area in the Eastern Interconnect, but has initiated a process to disconnect from the Eastern Interconnect and interconnect to ERCOT. Depending on the resolution of that case, the facility will either be connected to ERCOT or it will be connected to the SPP/ETI Area. Therefore, we calculate one set of scenarios assuming Cottonwood is in the SPP/ETI Area and another set assuming it is in ERCOT.

In the next section, we present the results of the concentration analyses. In section C, we present the results of the pivotal supplier analysis.

## B. Market Concentration Results: ETI Area

In this section we present the market concentration results for the ETI Area. We provide three separate analyses. In subsection 1, we present the market concentration analysis for the zero-percent load obligation case, which is equivalent to the installed capacity analysis. In addition, we present various mitigation scenarios to illustrate their effect on the market concentration. The second and third analyses involve uncommitted capacity analyses for the 100-percent load obligation case and the 50-percent load obligation case. These two analyses are presented in subsection 2. Because the results of these two analyses indicate no potential competitive concerns, we did not analyze the effects of mitigation.

### 1. Installed Capacity Results

As discussed above, the installed capacity results are equivalent to a zero-percent load obligation case. In other words, all of the capacity owned by each supplier is included in the market, even if it is needed to satisfy load obligations in reality. Table 1 shows the installed capacity HHI calculation in the ETI Area for the case that assumes the Cottonwood facility remains in the ETI Area.

The table shows each supplier's physical capacity within the ETI Area as well as capacity imports. There are 960 MW of capacity purchases with 839 MW from sources outside the ETI Area. Most of the outside imports are from Entergy units in Louisiana serving ETI load, although some imports serve municipal entities. We assume Cottonwood is available at 600 MW and that Tenaska's Frontier unit is limited to 300 MW due to limits on the firm transmission available for these resources. Available transfer capability (ATC) indicates the unused capacity on the interfaces into the ETI Area. We assume the unused ATC cannot be withheld, so we attribute a market share of zero to the ATC in the HHI calculation.

**Table 1: Market Concentration in ETI Area: Installed Capacity**
Cottonwood Included

| Supplier | Owned capacity | Capacity Purchases/ Imports | Capacity Sales | Net Capacity | Share |
|---|---|---|---|---|---|
| ArcLight Capital Prtrs/Reliant Energy | 115 | - | - | 115 | 1.7% |
| ConocoPhillips/NRG Energy | 555 | - | - | 555 | 8.0% |
| Dupont | 75 | - | - | 75 | 1.1% |
| East Texas Electric Coop, Inc. | 340 | 239 | - | 579 | 8.3% |
| ***ETI*** | ***2,300*** | ***643*** | - | ***2,943*** | ***42.3%*** |
| Exxon Mobil Corp. | 495 | - | - | 495 | 7.1% |
| Kelson Energy | 600 | | | 600 | 8.6% |
| SRMPA | - | 77 | - | 77 | 1.1% |
| Sabine River Authority of Louisiana | 91 | - | 91 | - | 0.0% |
| Southwestern Power Administration | 52 | - | 52 | - | 0.0% |
| Tenaska, Inc. | 300 | - | - | 300 | 4.3% |
| ATC | | | | 1,224 | 0.0% |
| Total | 4,923 | 960 | 143 | 6,964 | |
| | | | | **HHI:** | **2,068** |

Note: Withholding of ATC is assumed to be impossible so market share is assumed to be zero. Reliability investments have no effect on ATC. Cottonwood (Kelson Energy) limited to 600 MW, Frontier (Tenaska) limited to 300 MW. Jointly-owned plants operated jointly.

Table 1 shows that ETI has a market share of 42.3 percent. The HHI in the ETI Area is 2,068. Due to the potential that Cottonwood may disconnect from the Eastern Interconnect we made the same calculations, but with Cottonwood's capacity removed. However, removing Cottonwood caused an increase in ATC of 131 MW, partially offsetting the capacity loss. The HHI in this alternative case (not shown) rose to 2,292.

The HHI for both cases is within the range that should support a workably competitive market. Additionally, HHI values must be evaluated in light of other factors. In this case, these factors include load obligations, excess capacity, reliability-must-run (RMR) obligations, and other factors that may increase or decrease the competitiveness of the market. As discussed in the next section, these factors tend to mitigate potential competitive concerns. Considering the HHI values and these other factors, we conclude that these results do not raise significant competitive concerns.

Nonetheless, we performed sensitivity analyses presented below that show how the market concentration in the ETI Area would be affected by two types of mitigation measures. The first is the expansion of the transmission capacity into the ETI Area to raise ATC values and allow increased competition from external suppliers. The second is capacity sales by ETI that would reduce ETI's market share.

For capacity sales we use 500 MW because it is approximately 15 percent of ETI's capacity in the area. Fifteen percent is the divestiture floor value in PURA. Table 2 shows the results of the mitigation analyses.

**Table 2: Summary of HHI Impact of Mitigation Measures**

| Case | ATC Mitigation (MW) | Cap Sale Mitigation (MW) | ETI Share | Total Capacity (MW) | HHI |
|---|---|---|---|---|---|
| **Cases with Cottonwood @ 600 MW** | | | | | |
| No Mitigation | 0 | 0 | 42.3% | 6,964 | 2,068 |
| 500 MW ATC Mitigation | 500 | 0 | 39.4% | 7,464 | 1,810 |
| 500 MW Capacity Sale (~15% Sale) | 0 | 500 | 34.8% | 6,963 | 1,544 |
| **Cases with Cottonwood @ 0 MW** | | | | | |
| No Mitigation | 0 | 0 | 45.3% | 6,495 | 2,292 |
| 500 MW ATC Mitigation | 500 | 0 | 42.1% | 6,995 | 1,976 |
| 500 MW Capacity Sale (~15% Sale) | 0 | 500 | 37.6% | 6,495 | 1,712 |

The table shows that both mitigation approaches are effective at reducing the HHI to less than 2,000. Capacity sales are generally more effective because they reduce the market share of the largest supplier (ETI) more directly. With Cottonwood out of the market, a 500 MW capacity sale mitigation reduces the HHI to 1,713 while the same amount of new transmission reduces it to 1,976.

The installed capacity analysis ignores the effects of load obligations, excess capacity, and RMR obligations. These are better captured in the uncommitted capacity and pivotal supplier analyses discussed below.

## 2. Uncommitted Capacity Results

The next analysis of uncommitted capacity shares accounts for load obligations by subtracting the peak load obligation from the suppliers' total resources. It is a variation on the installed capacity market analysis which implicitly assumes a zero percent load obligation.

The uncommitted capacity measure is typically a more accurate indicator of market power because it reflects the mitigation effects of load obligations (i.e. there is no incentive to withhold resources needed to serve load). We calculated the uncommitted capacity values for a 100-percent load obligation case and a 50-percent load obligation case. Table 3 shows the analysis for the 50-percent load obligation case with Cottonwood included.

**Table 3: Market Concentration Analysis ETI Area: Uncommitted Analysis**
50-Percent Load Obligation Case; Cottonwood Included

| Supplier | Owned Capacity | Firm Purchases /Imports | Firm Sales | Net Capacity | Load Obligation | Uncommitted Capacity | Share of Uncommitted Capacity |
|---|---|---|---|---|---|---|---|
| ETI | 2300 | 643 | 0 | 2943 | 2066 | 877 | 20.3% |
| Kelson Energy | 600 | 0 | 0 | 600 | 0 | 600 | 13.9% |
| Tenaska, Inc. | 300 | 0 | 0 | 300 | 0 | 300 | 6.9% |
| East Texas Electric Coop, Inc. | 340 | 189 | 0 | 529 | 479 | 50 | 1.2% |
| Exxon Mobil Corp. | 495 | 0 | 0 | 495 | 0 | 495 | 11.4% |
| ConocoPhillips/NRG Energy | 555 | 0 | 0 | 555 | 0 | 555 | 12.8% |
| SRMPA | 0 | 127 | 0 | 127 | 89 | 38 | 0.9% |
| Dupont | 75 | 0 | 0 | 75 | 0 | 75 | 1.7% |
| ArcLight Capital Partners/Reliant Energy | 115 | 0 | 0 | 115 | 0 | 115 | 2.7% |
| Sabine River Authority of Louisiana | 91 | 0 | 91 | 0 | 0 | 0 | 0.0% |
| Southwestern Power Administration | 52 | 0 | 52 | 0 | 0 | 0 | 0.0% |
| ATC | 1224 | 0 | 0 | 1224 | 0 | 1224 | 0.0% |
| Total | 4923 | 960 | 143 | 5740 | 2634 | 4329 | |
| | | | | | | **HHI** | **958** |

*Note* : Cottonwood (Kelson Energy) limited to 600 MW and Frontier (Tenaska) limited to 300. Withholding of ATC assumed to be impossible so market share is 0. Jointly-owned plants assumed to be operated jointly.

The table shows the owned physical capacity located in the ETI Area, as well as the capacity that is imported or exported over the interconnections into the ETI Area. Uncommitted capacity is defined as the net capacity less the load obligation. The uncommitted capacity value is the basis for the market shares and the HHI. The resulting HHI is 958, which indicates that the market is not concentrated.

Table 4 shows the 100-percent load obligation case. Uncommitted Capacity is reported as zero when load obligation is greater than net capacity. The table shows that the HHI in this case is also low at 861.

**Table 4: Market Concentration Analysis ETI Area: Uncommitted Analysis**
100-Percent Load Obligation Case; Cottonwood Included

| Supplier | Owned Capacity | Firm Purchases /Imports | Firm Sales | Net Capacity | Load Obligation | Uncommitted Capacity | Share of Uncommitted Capacity |
|---|---|---|---|---|---|---|---|
| ETI | 2300 | 643 | 0 | 2943 | 4131 | 0 | 0.0% |
| Kelson Energy | 600 | 0 | 0 | 600 | 0 | 600 | 17.4% |
| Tenaska, Inc. | 300 | 0 | 0 | 300 | 0 | 300 | 8.7% |
| East Texas Electric Coop, Inc. | 340 | 189 | 0 | 529 | 479 | 50 | 1.4% |
| Exxon Mobil Corp. | 495 | 0 | 0 | 495 | 0 | 495 | 14.3% |
| ConocoPhillips | 555 | 0 | 0 | 555 | 0 | 555 | 16.1% |
| NRG Energy, Inc. | 0 | 0 | 0 | 0 | 0 | 0 | 0.0% |
| SRMPA | 0 | 127 | 0 | 127 | 89 | 38 | 1.1% |
| Dupont | 75 | 0 | 0 | 75 | 0 | 75 | 2.2% |
| ArcLight Capital Partners, LLC | 115 | 0 | 0 | 115 | 0 | 115 | 3.3% |
| Reliant Energy | 0 | 0 | 0 | 0 | 0 | 0 | 0.0% |
| Sabine River Authority of Louisiana | 91 | 0 | 91 | 0 | 0 | 0 | 0.0% |
| Southwestern Power Administration | 52 | 0 | 52 | 0 | 0 | 0 | 0.0% |
| ATC | 1224 | 0 | 0 | 1224 | 0 | 1224 | 0.0% |
| Total | 4923 | 960 | 143 | 5740 | 4700 | 3452 | |
| | | | | | | **HHI** | **861** |

*Note* : Cottonwood (Kelson Energy) limited to 600 MW and Frontier (Tenaska) limited to 300. Withholding of ATC assumed to be impossible so market share is 0. Jointly-owned plants assumed to be operated jointly.

The results of both of the uncommitted capacity cases indicate that there are no competitive concerns. These low levels of market concentration can be explained by the fact that the load obligations substantially reduce ETI's available supply to service others. In fact, in the 100 percent case, ETI is a net buyer.[12] Because these results raise no competitive concerns, there is no need to show the effects of potential mitigation measures on the uncommitted capacity market concentration.

12 In the case with Cottonwood removed the HHIs are slightly lower. Hence, those case also do not reveal competitive concerns.

## C. Pivotal Supplier Results: ETI Area

Our next analysis seeks to determine if any suppliers may be "pivotal" in the ETI Area under peak demand conditions. A supplier is pivotal if its resources are necessary to satisfy the load and reserves within the area (in this case, the ETI Area). Pivotal supplier analyses provide a more reliable indicator of market power than HHI analyses in electricity markets because they capture the effects of excess capacity and other factors that affect the competitiveness of the market.

We determine whether a supplier is pivotal by comparing the demand in the area to the total supplies in the area, less uncommitted resources owned by the supplier in question. If the demand cannot be satisfied with these supplies, the supplier is pivotal. Only uncommitted resources of the supplier are removed from the total supply because only uncommitted capacity can be profitably withheld by the supplier.

We examine six cases in Table 5. We determine whether ETI is pivotal in cases assuming a load obligation of 100 percent, 50 percent, and 0 percent. These three cases are examined both with and without the Cottonwood facility.

**Table 5: Pivotal Supplier Analysis in the ETI Area**

| | ETI Net Supply | ETI Load Obligation | Uncommit. ETI Supply | ETI Area Supply | ETI Area Supply w/o ETI | ETI Area Load + Reserves | Pivotal |
|---|---|---|---|---|---|---|---|
| **Cases with Cottonwood at 600 MW** | | | | | | | |
| 100% Load Obligation | 2943 | 4131 | 0 | 6964 | 6964 | 4841 | *No* |
| 50% Load Obligation | 2943 | 2066 | 877 | 6964 | 6086 | 4841 | *No* |
| 0% Load Obligation | 2300 | 0 | 2300 | 6964 | 4664 | 4841 | *Yes* |
| **Cases with Cottonwood Removed** | | | | | | | |
| 100% Load Obligation | 2943 | 4131 | 0 | 6495 | 6495 | 4841 | *No* |
| 50% Load Obligation | 2943 | 2066 | 877 | 6495 | 5617 | 4841 | *No* |
| 0% Load Obligation | 2300 | 0 | 2300 | 6495 | 4195 | 4841 | *Yes* |

All values in MW. ETI net supply decreases in no-load obligation case because ETI is assumed to no longer control firm transmission into ETI.

The table shows the ETI net supply, which includes its internal generating resources and the import capability ETI can control by designating external resources to be imported to serve the load. In the zero-percent load obligation case, ETI's net capacity declines because we assume that ETI will not have the ability to hold the firm transmission into the ETI Area. This assumption is based on the fact that firm transmission is acquired by designating network resources outside the ETI Area to serve load within the area. If a supplier has no load to serve, it will not have the ability to designate network resources and occupy the firm transmission into the ETI Area. Accordingly, ETI is no longer entitled to the 643 MW of network transmission rights reflected in the 100-percent and 50-percent load obligation cases.

The pivotal supplier calculation is performed on the right-hand side of the table where the total ETI Area supply (including import capability) is reduced by ETI's uncommitted capacity, and compared to the total demand in the area (i.e., load plus reserve requirements).[13] ETI is pivotal if the supply in the area not controlled by ETI does not exceed the total demand in the area. The results of our analysis show that ETI is only pivotal in the 0 percent load case, both with and without Cottonwood. With Cottonwood included, only roughly 180 MW of demand could not be served without ETI's resources. Without Cottonwood, the unsatisfied demand could climb to approximately 650 MW. Because ETI has 2300 MW of supply, it would therefore have to withhold roughly 1650 MW in the case without Cottonwood to raise prices to the residual 650 MW of peak load in the ETI Area.

The indication that ETI is pivotal in these cases raises potential competitive concerns. However, this does not mean that it actually has market power. In order to have market power, ETI must have the ability to withhold the resources necessary to raise prices and profit by doing so. Based on our review of the relevant factors that bear on ETI's ability and incentives to withhold resources, we find that market power mitigation should not be necessary to achieve a workably competitive market in the ETI Area. This finding is based, in part, on the following factors:

First, a significant portion of ETI's capacity is reliability-must-run, which means that they must be operated to support the transmission system. Because RMR resources cannot be withheld by the supplier, they should not be included in the pivotal supplier test. ETI is not pivotal if it cannot withhold such capacity.

[13] Reserves are assumed to be three percent of load.

Second, ETI will likely continue to be obligated to serve load as a provider-of-last-resort. POLR prices in ERCOT are capped relative to prevailing wholesale prices. It is unclear what "price-to-beat" or POLR provisions would be applied in the ETI Area. However, because ETI would have to withhold the majority of its resources in order to receive the price-to-beat or POLR price from the remaining retail customers, such a strategy would only be economic if the PUCT allowed extremely high POLR pricing. We believe that this is unlikely and withholding of this magnitude, therefore, is unlikely to be economic.

Third, in the cases where ETI is pivotal, it is only pivotal in a small number of hours. The pivotal supplier analysis uses the load forecast for the annual peak of the year. In general, the load declines sharply from the annual peak hour to other hours, which limits the extent to which ETI is pivotal. In other words, ETI's resources would only be needed to serve a portion of the load when load levels are close to the annual peak.

Finally, as an RTO, SPP will have a market monitor and market power mitigation measures necessary to address market power in the region. Given the vast quantities of withholding that would be necessary exploit ETI's pivotal supplier status, its conduct would not go unnoticed by the market monitor or FERC.

# IV. ANALYSIS OF LOCAL MARKET POWER IN WESTERN SUBREGION OF ETI AREA

In this section of the report, we review the market concentration and the pivotal supplier analyses for the Western Subregion of the ETI Area. The Western Subregion is defined as the load and resources in the ETI Area west of the Jacinto and Cypress substations. We analyze it separately because transmission constraints limit the extent to which load in the area can be served by resources outside of the Western Subregion. Section A below contains the market concentration analysis of the Western Subregion while Section B contains the pivotal supplier analysis.

Based on information from ETI, we assume a transfer capability into the Western Subregion from the rest of ETI of [redacted]. Like the analyses for the entire ETI Area, we produce results for three scenarios with varying load obligation assumptions. Cottonwood is not located in the Western Subregion so we do not model the alternative Cottonwood scenarios. Tenaska's Frontier unit is located in the Western Subregion and we do continue to limit that unit to 300 MW in each of the analyses.

## A. Market Concentration Results: Western Subregion

As with the broader ETI Area, we produce market concentration results for three scenarios. One scenario for installed capacity (zero-percent load obligation case) and two for the uncommitted capacity case (50-percent load obligation case, and 100-percent load obligation case).

Like the previous analyses, we assume the rights to the transfer capability (which can be used to serve a large share of the load in the area) can only be held by entities serving load in the area. Because the installed capacity analysis assumes no load obligation, the [redacted] of transfer capability is open to all market participants. In the 50-percent and 100-percent cases, we assume that ETI controls the portion of the interface capability into the Western Subregion that corresponds to the load that they serve in the area. In other words, we assume that they can serve their load with resources outside of the Western Subregion, effectively preventing competing suppliers from using this capability.

We assume any transfer capability not held by suppliers within the Western Subregion is available on a competitive basis with no single firm having a significant market share (or the ability to prevent others from using the import capability). These assumptions are bolstered by the fact that the SPP will operate a real-time market that will fully use the transmission capability into the area. This real-time market will provide a supplemental source of supply for competitive retail suppliers. For purposes of these analyses, the assumption that transmission capability will be competitively available is reflected by attributing a market share of zero for the transfer capability.

**Table 6: Market Concentration in Western Subregion: Installed Capacity**

Redacted

The market concentration analysis for the Installed Capacity case is shown above in Table 6. The HHI in this case is well below the 1,000 level. This indicates that the market is unconcentrated and raises no significant competitive concerns.

The analysis of uncommitted capacity under a 50-perent-load-obligation scenario is shown in Table 7.

**Table 7: Concentration of Uncommitted Capacity Western Subregion**
50-Percent-Load-Obligation

Redacted

ETI's net capacity in the Western Subregion grows from 456 MW in the Installed Capacity case to [redacted] in this case because we assume that it will have the ability to control [redacted] of the [redacted] of total transfer capability. Likewise, East Texas Electric Cooperative is assumed to control firm import capacity needed to serve its 50-percent load obligation. The smaller quantity of remaining rights is released to the market. These changes increase the market share of ETI and the overall market concentration. As the table shows, the HHI in this case is 1,560. It remains well below levels that would raise competitive concerns.

The analysis of uncommitted capacity in the 100-perent-load-obligation scenario results in a very high HHI. However, all load serving entities have sufficient capacity to serve their own load so competitive concerns are limited.

In summary, the three market concentration analyses in this subsection do not raise significant market power concerns in the Western Subregion.

### B. Pivotal Supplier Results: Western Subregion

In this section, we present our pivotal supplier analysis for the Western Subregion. Like the concentration analysis, we consider three load-obligation scenarios (0 percent, 50 percent, and 100 percent). ETI's net supply in the 100 percent load obligation case is equal to its load obligation. This occurs because ETI's load obligation is greater than its physical generating capacity in the Western Subregion. Therefore, ETI uses the transfer capability to serve the balance of its load.

In the 50-percent load obligation case, ETI is able to retain transfer rights up to its assumed load obligation (50 percent of its current load). Hence, the ETI net supply in that case is the ETI load obligation plus ETI's physical generation capacity in the subregion (456 MW). In the zero-percent load obligation case, ETI net supply is equal to its physical capacity because it cannot retain network transmission rights without load obligations.

A summary of the pivotal supplier analysis of the Western Subregion is shown in Table 8. The pivotal supplier calculations are shown on the right-hand side of the table. The total ETI area supply is reduced by ETI uncommitted capacity and compared to the Western Subregion load plus reserves. Reserves are assumed to be three percent of load.

**Table 8: Pivotal Supplier Analysis – Western Subegion**

Redacted

In summary, the table shows that ETI is not pivotal in any of the cases. Even if they were, however, market power concerns would be substantially mitigated by the fact [redacted].

These results confirm the conclusions from the market concentration analyses that there are not significant competitive concerns associated with satisfying the demand in the Western Subregion.

## V. CONCLUSION

The results of our analyses of the ETI Area and the Western Subregion in ETI do not raise substantial competitive concerns. Hence, we find that market power mitigation measures are not necessary to address competitive issues in this case.

However, a subset of the market power measures we present in this report do indicate potential concerns. In particular, the market concentration levels both with and without Cottonwood are at the high end of levels that we would consider workably competitive. Additionally, ETI is pivotal in cases where it has no load obligations. However, there are a number of factors that mitigate any potential competitive concerns raised by these results. These factors include:

- ETI has a number of RMR obligations that compel its generation to run to support the reliability of the system, which would prevent it from withholding its supply.
- It is unlikely to be profitable for ETI to exercise market power as ETI would have to withhold most of its resources to raise prices to a small portion of load. Further, the magnitude of that price increase would be limited by ETI's potential POLR obligations.
- ETI is pivotal in only a small number of hours when load is near the annual peak.
- SPP will have a market monitor and market power mitigation necessary to address market power in the region.

Nonetheless, if policymakers desire additional assurance that the market will perform competitively, implementing a capacity auction for 15 percent or more of ETI's capacity as called for in PURA would lower concentration levels and reduce the extent to which ETI is pivotal. Unless additional transmission capacity can be built that produces net benefits to the region, the capacity auctions are likely the most cost-effective form of market power mitigation.

## Appendix 4: Energy Construction Plan

Posted at

http://oasis.e-terrasolutions.com/documents/EES/2009-11%20ETR%20Construction%20Plan%20(April%2017%202008%20Rev%20-%20Final).pdf

## Appendix 5: STEP Plan

Posted at

http://www.spp.org/publications/2007%20SPP%20Transmission%20Expansion%20Plan%2020080131_BOD_Public.pdf

## Appendix 6: SPP-Entergy SPP_ETI Integration Summary Stability Report

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# The SPP-Entergy Stability Study to Evaluate the Proposed SPP/Entergy Texas System Integration

## Project 18554-21-00
## Summary Report # 18554-21-00-3

## December 02, 2008

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# 1 Introduction

Currently, Entergy owns and operates a portion of the electric grid in the eastern part of Texas, which is known as Entergy Texas, Inc. (ETI). As part of ETI's transition to competition proposal, one of the options being considered by ETI is to move its service territory into the Southwest Power Pool (SPP). In order to determine how to integrate ETI into SPP reliably, Entergy and SPP have embarked on a joint study divided into two phases, namely, steady state analysis and stability analysis.

As part of the steady state analysis, a minimum set of reliability and economic projects required to meet the minimum transfer requirements into ETI, as well as the North-American Electric Reliability Corporation (NERC) and SPP reliability criteria, is identified. In the proposed stability study, the initial set of projects that have been agreed upon by SPP and Entergy will be included in the model and extensive stability analysis will be performed in the Eastern Interconnect (EI) portion of Entergy and SPP to meet NERC reliability criteria. If stability problems are identified, additional reinforcements will be added until all NERC and Entergy/SPP criteria are addressed.

Powertech Labs, Inc. (PLI) has been contracted to conduct this phase of the study, which is concerned with voltage security, transient security, and small-signal stability issues. Voltage security will include voltage stability/collapse, bus voltage magnitude decline/rise, and branch overload issues, which are also collectively referred to as static studies. Dynamic studies, on the other hand, will contain those related to transient security and small signal stability, namely, transient stability/separation, transient voltage dips, and damping issues.

Note that this report is concerned with the results of a high level study to address the above issues, in which the scope is reduced to a handful of specified contingencies. The full study concerning a thorough contingency screening is due to be performed in near future.

# 2 Model Development

## 2.1 Simulation Tools

The studies were based on computer simulations using the following programs of PLI's DSA*Tools*™ software (http://www.dsatools.com):

- Power-flow and Short-circuit Analysis Tool (PSAT).
- Voltage Security Assessment Tool (VSAT).
- Transient Security Assessment Tool (TSAT).

These programs automatically convert the power flow and dynamic data from PSS/E format. Special (non-convertible) models were set up through the User-Defined Model (UDM) capability of the software. The following features of these programs were also used for sanity checking of data:

- Power flow data checking capability of PSAT and VSAT.
- Dynamic data checking capability of TSAT.
- Visual checks using various data tabulations.

## 2.2 Base Power Flows

In this study, Entergy and SPP initially supplied three base power flow cases representing the whole EI system. These cases are as follows:

1. 2012 Summer Peak Loading Condition with Cottonwood Generation and without Series Compensation of Mt. Olive – Hartburg 500 kV line (12S+CW-SC).
2. 2012 Summer Peak Loading Condition without Cottonwood Generation and with 30% Series Compensation of Mt. Olive – Hartburg 500 kV line (12S-CW+SC).
3. 2012 Summer Peak Loading Condition without Cottonwood Generation and without Series Compensation of Mt. Olive – Hartburg 500 kV line (12S-CW-SC).

The summaries of the base cases are shown in Table 2-1.

*Table 2-1: Base Power Flow Summaries.*

| Base Case | Generation MW / MVAR | | Load MW / MVAR | |
|---|---|---|---|---|
| | EI | ETI | EI | ETI |
| 12S+CW-SC | 729852 / 160003 | 3087 / 893 | 711449 / 199657 | 4688 / 1489 |
| 12S-CW+SC | 729865 / 160161 | 2985 / 907 | 711441 / 199657 | 4684 / 1489 |
| 12S-CW-SC | 729869 / 160172 | 2984 / 942 | 711441 / 199657 | 4684 / 1489 |

## 2.3 Dynamic Data

Entergy-SPP provided the dynamic data of the EI system, including the ETI area, matching the base power flows. PLI added the controls data for the existing HVDC links in the EI system. Data issues were insignificant and mostly remote to Entergy and SPP.

## 2.4 Load Models

Throughout the EI system, constant power load was used in static studies for both active and reactive components. In dynamic studies, constant impedance, constant current, and constant power (ZIP) load models were implemented based on the conversion percentages for various areas and buses provided by Entergy and SPP.

## 2.5 Study Regions

The focus of this project was to examine the integrated system within ETI and relevant parts of the Entergy and SPP systems around it. The corresponding regions were defined as follows:

- ETI region (considered as part of Entergy but monitored in both Entergy and SPP evaluations): Area 551 (ETI).
- Nearby Entergy region: Areas 331 (BCA), 332 (LAGN), 334 (WESTMEMP), 335 (CONWAY), 336 (BUBA), 337 (PUPP), 338 (DERS), 339 (DENL), and 351 (EES).
- Nearby SPP region: Areas 502 (CELE), 503 (LAFA), 504 (LEPA), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), and 526 (SPS).

All buses at 115 kV and higher, as well as all 100 MVA or larger generating units, were monitored in the corresponding regions for bus voltage, branch current, and other criteria violations, in both static and dynamic studies.

## 2.6 Applied Criteria

For the Entergy and SPP, as well as the ETI grid (assessed by Entergy criteria), the applied criteria is as follows:

- Voltage decline: 0.92 pu for all 115 kV and higher buses, in the study region.
- Branch overload: 100% of rating "A" for 115 kV and higher in the study region of Entergy, and 100% of rating "B" for 115 kV and higher in the study region of SPP.
- Transient stability: all units remaining in synchronism.
- Dynamic voltage: 115 kV and higher buses having no more than 20% dips, lasting no more than 20 cycles for single contingencies, and 40 cycles for double contingencies, in the study region.
- Damping: 5%.

The above criteria were applied to pre-contingency conditions of the three base cases, as well as when subjected to contingencies described in the next subsection.

## 2.7 Applied Contingencies

Entergy and SPP provided specific lists of N-2 contingencies each consisting of a single branch, either transmission line or transformer, and a generating unit. Table 2-2 through Table 2-5 show these contingencies for both static and dynamic studies. Note that in the cases without Cottonwood, Nelson unit 6 (G6) is used instead of Cottonwood steam and gas unit pair (G5). Furthermore, L1 and L3 were used in three sensitivity scenarios described in Section 3.3.

*Table 2-2: Entergy Contingencies for Static Studies.*

| Cont. # & Name | | Branch | | | | | Generator | | |
|---|---|---|---|---|---|---|---|---|---|
| | | From Bus # & Name | | To Bus # & Name | | ID | Bus # &Name | | ID |
| 1 | G1+L1 | 334204 | 6CHINA 230. | 334200 | 6PORTER 230. | 1 | 334070 | G1LEWIS 22.0 | 1 |
| 2 | G2+L2 | 334206 | 6JACINTO230. | 334204 | 6CHINA 230. | 1 | 334758 | JAC_U1 13.8 | 1 |
| 3 | G3+L3 | 334325 | 8HARTBRG500. | 334320 | 8CYPRESS500. | 1 | 334298 | CYPR U1 13.8 | 1 |
| 4 | G4+L4 | 334204 | 6CHINA 230. | 334434 | 6SABINE 230. | 1 | 334440 | G4SABIN 24.0 | 1 |
| 5 | G5+L5 | 337368 | 8MTOLIV 500. | 334325 | 8HARTBRG500. | 1 | 303027<br>303026 | 1S4INTHB13.8<br>1G4INTHB18.0 | 1 |
| 6 | G6+L6 | 334325 | 8HARTBRG500. | 335192 | 8NELSON 500. | 1 | 335206 | G6NELSON20.0 | 1 |

*Table 2-3: SPP Contingencies for Static Studies.*

| Cont. # & Name | | Branch | | | | | Generator | | |
|---|---|---|---|---|---|---|---|---|---|
| | | From Bus # & Name | | To Bus # & Name | | ID | Bus # &Name | | ID |
| 1 | G1+X1 | 500250 | DOLHILL7345. | 500260 | DOLHILL6230. | 1 | 501813 | G3RODEMR22.0 | 1 |
| 2 | G1+X4 | 500470 | LEESV 6 230. | 500480 | LEESV 4 138. | 1 | 501813 | G3RODEMR22.0 | 1 |
| 3 | G1+L2 | 500250 | DOLHILL7345. | 507760 | SW SHV7 345. | 1 | 501813 | G3RODEMR22.0 | 1 |
| 4 | G1+L5 | 500280 | ELEESV6 230. | 500770 | RODEMR 6230. | 1 | 501813 | G3RODEMR22.0 | 1 |
| 5 | G2+L1 | 508572 | LEBROCK7345. | 508585 | TENRUSK7345. | 1 | 509403 | PIRKEY1 23.4 | 1 |
| 6 | G2+L6 | 508298 | LYDIA 7 345. | 510911 | VALIANT7345. | 1 | 509403 | PIRKEY1 23.4 | 1 |
| 7 | G2+L7 | 510907 | PITSB-7 345. | 515136 | SUNNYSD7345. | 1 | 509403 | PIRKEY1 23.4 | 1 |
| 8 | G5+L1 | 508572 | LEBROCK7345. | 508585 | TENRUSK7345. | 1 | 515225 | MUSKOG5G18.0 | 1 |
| 9 | G5+L6 | 508298 | LYDIA 7 345. | 510911 | VALIANT7345. | 1 | 515225 | MUSKOG5G18.0 | 1 |
| 10 | G5+L7 | 510907 | PITSB-7 345. | 515136 | SUNNYSD7345. | 1 | 515225 | MUSKOG5G18.0 | 1 |

*Table 2-4: Entergy Contingencies for Dynamic Studies.*

| Cont. # & Name | | Branch | | | | | Generator | | |
|---|---|---|---|---|---|---|---|---|---|
| | | From Bus # & Name | | To Bus # & Name | | ID | Bus # &Name | | ID |
| 1 | G1+B1 | 334067 | 6LEWISCR230. | 334072 | 4LEWIS 138. | 1 | 334070 | G1LEWIS 22.0 | 1 |
| 2 | G1+B2 | 334072 | 4LEWIS 138. | 334090 | 4ALDEN 138. | 1 | 334070 | G1LEWIS 22.0 | 1 |
| 3 | G2+B3 | 334206 | 6JACINTO230. | 334208<br>334207 | 4JACINTO138.<br>1JACINTO13.8 | 1 | 334758 | JAC_U1 13.8 | 1 |
| 4 | G3+B4 | 334320 | 8CYPRESS500. | 334326 | 6CYPRESS230. | 1 | 334298 | CYPR U1 13.8 | 1 |
| 5 | G3+B5 | 334206 | 6JACINTO230. | 334326 | 6CYPRESS230. | 1 | 334298 | CYPR U1 13.8 | 1 |
| 6 | G4+B6 | 334204 | 6CHINA 230. | 334434 | 6SABINE 230. | 1 | 334440 | G4SABIN 24.0 | 1 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 7 | G4+B7 | 334434 | 6SABINE 230. | 335070 | 6CARLYSS230. | 1 | 334440 | G4SABIN 24.0 | 1 |
| 8 | G5+B8 | 334325 | 8HARTBRG500. | 335192 | 8NELSON 500. | 1 | 303027<br>303026 | 1S4INTHB13.8<br>1G4INTHB18.0 | 1 |
| 9 | G5+B9 | 334325 | 8HARTBRG500. | 334320 | 8CYPRESS500. | 1 | 303027<br>303026 | 1S4INTHB13.8<br>1G4INTHB18.0 | 1 |
| 10 | G6+B10 | 335192 | 8NELSON 500. | 335190 | 6NLSON 230. | 1 | 335206 | G6NELSON20.0 | 1 |

*Table 2-5: SPP Contingencies for Dynamic Studies.*

| Cont. # & Name | | Branch | | | | | Generator | | |
|---|---|---|---|---|---|---|---|---|---|
| | | From Bus # & Name | | To Bus # & Name | | ID | Bus # &Name | | ID |
| 1 | G1+X1 | 500250 | DOLHILL7345. | 500260 | DOLHILL6230. | 1 | 501813 | G3RODEMR22.0 | 1 |
| 2 | G1+X4 | 500470 | LEESV 6 230. | 500480 | LEESV 4 138. | 1 | 501813 | G3RODEMR22.0 | 1 |
| 3 | G1+L2 | 500250 | DOLHILL7345. | 507760 | SW SHV7 345. | 1 | 501813 | G3RODEMR22.0 | 1 |
| 4 | G1+L5 | 500280 | ELEESV6 230. | 500770 | RODEMR 6230. | 1 | 501813 | G3RODEMR22.0 | 1 |
| 5 | G2+L1 | 508572 | LEBROCK7345. | 508585 | TENRUSK7345. | 1 | 509403 | PIRKEY1 23.4 | 1 |
| 6 | G2+L6 | 508298 | LYDIA 7 345. | 510911 | VALIANT7345. | 1 | 509403 | PIRKEY1 23.4 | 1 |
| 7 | G5+L7 | 500250 | DOLHILL7345. | 500260 | DOLHILL6230. | 1 | 501801 | G1DOLHIL24.0 | 1 |
| 8 | G5+L1 | 500470 | LEESV 6 230. | 500480 | LEESV 4 138. | 1 | 501801 | G1DOLHIL24.0 | 1 |
| 9 | G5+L6 | 500250 | DOLHILL7345. | 507760 | SW SHV7 345. | 1 | 501801 | G1DOLHIL24.0 | 1 |
| 10 | G5+L7 | 500280 | ELEESV6 230. | 500770 | RODEMR 6230. | 1 | 501801 | G1DOLHIL24.0 | 1 |

For transient simulations the single branch outages were first simulated with a 3-phase fault at either end to identify the more significant end. The N-2 contingencies were then simulated with the 3-phase fault at this end. The applied fault durations are presented in Table 2-6. Unsymmetrical faults were not considered in this project, as the zero sequence data corresponding to the new configuration was not available.

*Table 2-6: Applied Durations for the 3-Phase Faults.*

| Voltage Level | Fault Duration (Cycles) |
|---|---|
| 500 kV | 4 |
| 345 kV | 5 |
| 230 kV | 6 |
| 161 kV | 6 |
| 138 kV | 6 |
| 115 kV | 6 |

Multiple contingencies, where two or more branches are tripped simultaneously, were also supplied as follows:

- 9 multiple contingencies in Entergy system, which were identified as contingencies 800, 801, 802, 803, 806, 807, 809, 810, and 811.
- 46 multiple contingencies in SPP system, which were identified as DOLHILL6, RICHARD, RAPIDES6, AEPW-01, AEPW-02, AEPW-04, AEPW-05, AEPW-06, AEPW-07, AEPW-08, AEPW-09, AEPW-10, AEPW-11, AEPW-12, AEPW-14, AEPW-

15, AEPW-17, AEPW-18, AEPW-19, AEPW-20, AEPW-21, AEPW-22, AEPW-23a, AEPW-23b, AEPW-24, AEPW-25, AEPW-26, AEPW-27, AEPW-28, CELE-01, CELE-02, CELE-03, GRDA-01, KCPL-01, KCPL-02, OKGE-01, SWPA-01, SWPA-02, SWPA-03, SWPA-04, SWPA-05, SWPA-06, SWPA-07, SWPA-08, SWPA-09, SWPA-10.

These contingencies were also applied in both static and dynamic simulations, where a 3-phase fault at the first bus (with appropriate duration) is assumed for the latter.

## 2.8 Applied Transfers

For both static and dynamic studies the following transfer was considered for stressing the system:

- **Source:** Generation increase, 50% in areas 515, 520, 523, and 524 (i.e., SPP) and 50% in area 351 (i.e., Entergy).
- **Sink:** Load increase, 100% in area 551 (i.e., ETI).

Furthermore, three sensitivity scenarios (described in Section 3.3) were studied with a transfer having the same source as above, but with generation decrease of G1LEWIS, G2LEWIS, G1SABIN, G2SABIN, G3SABIN, G4SABIN, and G5SABIN as the sink.

# 3 Voltage Security Studies

In voltage security studies Under-Load Tap Changer (ULTC) and switched shunt controls were enabled for both pre- and post-contingency analyses. Moreover, typical governor action (i.e., 4% droop) of the Entergy and SPP areas was also considered in post-contingency situations.

## 3.1 Voltage Security Findings in the Entergy System

Before applying the transfer, there was one bus voltage violation at 335385 (4LEROY 138.) and one branch overload of 337678 (3BISMRK 115.) – 3377685 (3HSEHVW 115.) – '1'. The former was fixed through an IDEV file supplied by Entergy and the latter was ignored (far from focus region). The Voltage Stability (VS) limits of the three base cases after applying the transfer are summarized in Table 3-1.

*Table 3-1: Voltage Stability Limits for Entergy Contingencies.*

| Base Case | VS Limit (MW) | Limiting Contingency |
|---|---|---|
| 12S+CW-SC | 600 | G1+L1 |
| 12S-CW+SC | 450 | G1+L1 |
| 12S-CW-SC | 450 | G1+L1 |

The bus voltage violations and branch overloads at the VS limits are summarized in Table 3-2 and Table 3-3, respectively, which are not very severe. The decline column in Table 3-2 is the amount of voltage that goes below the criterion of 0.92 pu (e.g., 0.02 pu decline would indicate 0.90 pu bus voltage).

*Table 3-2: Top 10 Bus Voltage Violations at VS Limit for Entergy Contingencies.*

| Base Case | Bus # & Name | | Decline (PU) | Critical Contingency |
|---|---|---|---|---|
| 12S+CW-SC | 334059 | 4WYNTEX 138. | 0.0245 | G1+L1 |
| | 334057 | 4HUNTSVL138. | 0.0242 | G1+L1 |
| | 334058 | L558T485138. | 0.0229 | G1+L1 |
| | 334056 | L558TP91138. | 0.0210 | G1+L1 |
| | 334052 | 4CEDAR 138. | 0.0198 | G1+L1 |
| | 334060 | 4MT.ZION138. | 0.0196 | G1+L1 |
| | 334051 | 4BISHOP 138. | 0.0193 | G1+L1 |
| | 334053 | 4CINCINT138. | 0.0189 | G1+L1 |
| | 334043 | 4TUBULAR138. | 0.0184 | G1+L1 |
| | 334050 | 4PEE DEE138. | 0.0183 | G1+L1 |
| 12S-CW+SC | 334059 | 4WYNTEX 138. | 0.0274 | G1+L1 |
| | 334057 | 4HUNTSVL138. | 0.0264 | G1+L1 |
| | 334058 | L558T485138. | 0.0247 | G1+L1 |
| | 334056 | L558TP91138. | 0.0239 | G1+L1 |
| | 334052 | 4CEDAR 138. | 0.0224 | G1+L1 |

| | | | | |
|---|---|---|---|---|
| | 334053 | 4CINCINT138. | 0.0224 | G1+L1 |
| | 334054 | 4WALKER 138. | 0.0214 | G1+L1 |
| | 334051 | 4BISHOP 138. | 0.0212 | G1+L1 |
| | 334060 | 4MT.ZION138. | 0.0206 | G1+L1 |
| | 334050 | 4PEE DEE138. | 0.0195 | G1+L1 |
| 12S-CW-SC | 334059 | 4WYNTEX 138. | 0.0338 | G1+L1 |
| | 334057 | 4HUNTSVL138. | 0.0328 | G1+L1 |
| | 334058 | L558T485138. | 0.0313 | G1+L1 |
| | 334056 | L558TP91138. | 0.0304 | G1+L1 |
| | 334052 | 4CEDAR 138. | 0.0290 | G1+L1 |
| | 334053 | 4CINCINT138. | 0.0289 | G1+L1 |
| | 334054 | 4WALKER 138. | 0.0279 | G1+L1 |
| | 334051 | 4BISHOP 138. | 0.0279 | G1+L1 |
| | 334060 | 4MT.ZION138. | 0.0273 | G1+L1 |
| | 334050 | 4PEE DEE138. | 0.0263 | G1+L1 |

*Table 3-3: Branch Loading Violations at VS Limit for Entergy Contingencies.*

| Base Case | From Bus # & Name | | To Bus # & Name | | ID | % Load | Critical Contingency |
|---|---|---|---|---|---|---|---|
| 12S+CW-SC | 335368 | 8WELLS 500. | 335500 | 8WEBRE 500. | 1 | 115.7 | G6+L6 |
| | 334067 | 6LEWISCR230. | 334072 | 4LEWIS 138. | 1 | 109.4 | G6+L5 |
| | 334281 | 4FORK CK138. | 334282 | 4RAYBURN138. | 1 | 107.9 | G6+L5 |
| | 334334 | 4LEACH 138. | 334335 | 4TOLEDO 138. | 1 | 106.0 | G3+L3 |
| | 334333 | 4NEWTONB138. | 334334 | 4LEACH 138. | 1 | 104.1 | G1+L1 |
| | 334327 | 6AMELIA 230. | 334360 | 6HELBIG 230. | 1 | 101.5 | G3+L3 |
| | 334391 | 4CARROLS138. | 334396 | 47NECHES138. | 2 | 117.3 | 810 |
| | 334438 | 6HANKS 230. | 334445 | 6GULFWAY230. | 1 | 106.3 | 807 |
| 12S-CW+SC | 334334 | 4LEACH 138. | 334335 | 4TOLEDO 138. | 1 | 110.1 | G6+L5 |
| | 335192 | 8NELSON 500. | 335190 | 6NLSON 230. | 1 | 108.3 | G6+L6 |
| | 334333 | 4NEWTONB138. | 334334 | 4LEACH 138. | 1 | 108.3 | G6+L5 |
| | 334281 | 4FORK CK138. | 334282 | 4RAYBURN138. | 1 | 106.9 | G3+L3 |
| | 334067 | 6LEWISCR230. | 334072 | 4LEWIS 138. | 1 | 105.9 | G1+L1 |
| | 334391 | 4CARROLS138. | 334396 | 47NECHES138. | 2 | 112.9 | 810 |
| | 334438 | 6HANKS 230. | 334445 | 6GULFWAY230. | 1 | 103.8 | 807 |
| 12S-CW-SC | 335192 | 8NELSON 500. | 335190 | 6NLSON 230. | 1 | 117.1 | G6+L5 |
| | 334334 | 4LEACH 138. | 334335 | 4TOLEDO 138. | 1 | 110.4 | G6+L6 |
| | 334333 | 4NEWTONB138. | 334334 | 4LEACH 138. | 1 | 108.6 | G6+L5 |
| | 334281 | 4FORK CK138. | 334282 | 4RAYBURN138. | 1 | 108.3 | G3+L3 |
| | 334067 | 6LEWISCR230. | 334072 | 4LEWIS 138. | 1 | 105.6 | G1+L1 |
| | 334391 | 4CARROLS138. | 334396 | 47NECHES138. | 2 | 112.7 | 810 |
| | 334438 | 6HANKS 230. | 334445 | 6GULFWAY230. | 1 | 104.3 | 807 |

## 3.2 Voltage Security Findings in the SPP System

Before applying the transfer, there were six bus voltage violations at 500010 (ABBEVL 4138.), 503306 (ABBVILL4138.), 502404 (BONIN 4138.), 500380 (GUIDRY 4138.), 500720 (PLAISAN4138.), and 505588 (STIGLER5138.), and two branch overloads of 502403

(BONIN 6230.) – 502404 (BONIN 4138.) – '1' and 502404 (BONIN 4138.) – 335379 (4SCOTT1 138.) – '1'. The first three voltage violations and the two branch overloads were fixed through an IDEV file supplied by SPP and the three remaining voltage violations were ignored. The Voltage Stability (VS) limits of the three base cases after applying the transfer are summarized in Table 3-4.

*Table 3-4: Voltage Stability Limits for SPP Contingencies.*

| Base Case | VS Limit (MW) | Limiting Contingency |
|---|---|---|
| 12S+CW-SC | 950 | G2+L1 or G5+L1 |
| 12S-CW+SC | 800 | G2+L1 or G5+L1 |
| 12S-CW-SC | 750 | G2+L1 or G5+L1 |

These limits are much higher than those of Entergy contingencies. As a result, for SPP contingencies there were no bus voltage or branch loading violations at the minimum limits reported in Table 3-1.

## 3.3 Voltage Security Findings of Sensitivity Scenarios

Three sensitivity scenarios were studied for all three base power flows as described in Table 3-5. Their Voltage Stability (VS) limits after applying the corresponding transfer (i.e., generation increase in EI against generation decrease in ETI) are summarized in Table 3-6.

*Table 3-5: Sensitivity Scenarios for Each of The Three Base Cases.*

| Scenario # | Additional Unit Outage at Pre-contingency | Contingency |
|---|---|---|
| 1 | – | G2LEWIS Unit + Porter – China 230 kV Line |
| 2 | G1LEWIS | G2LEWIS Unit + Porter – China 230 kV Line |
| 3 | G5SABIN | G4SABIN Unit + Cypress – Hartburg 500 kV Line |

*Table 3-6: Voltage Stability Limits for Sensitivity Scenarios.*

| Base Case | VS Limit (MW) | | |
|---|---|---|---|
| | Scenario 1 | Scenario 2 | Scenario 3 |
| 12S+CW-SC | >1000 | >1000 | 650 |
| 12S-CW+SC | >1000 | 350 | 400 |
| 12S-CW-SC | >1000 | 100 | 350 |

The bus voltage violations and branch overloads at the limits of Table 3-5 are summarized in Table 3-7 and Table 3-8, respectively.

*Table 3-7: Top 10 Bus Voltage Violations at VS Limit for Sensitivity Scenarios.*

| Base Case | Bus # | Name | Decline (PU) | Scenario # |
|---|---|---|---|---|
| 12S+CW-SC | None (up to 1000 MW Transfer) | | | 1 |
| | 334057 | 4HUNTSVL138. | 0.0330 | 2 |
| | 334028 | 7GRIMES 345. | 0.0327 | 2 |
| | 334029 | 7FRONTR 345. | 0.0327 | 2 |
| | 334058 | L558T485138. | 0.0323 | 2 |
| | 334059 | 4WYNTEX 138. | 0.0309 | 2 |
| | 334060 | 4MT.ZION138. | 0.0305 | 2 |
| | 334043 | 4TUBULAR138. | 0.0301 | 2 |
| | 334044 | 4DOBBIN 138. | 0.0300 | 2 |
| | 334023 | 4NAVSOTA138. | 0.0297 | 2 |
| | 334024 | 4SOTA 1138. | 0.0279 | 2 |
| | 334028 | 7GRIMES 345. | 0.0423 | 3 |
| | 334029 | 7FRONTR 345. | 0.0423 | 3 |
| | 334442 | 6KEITHLA230. | 0.0391 | 3 |
| | 334443 | 6SOSIDE 230. | 0.0383 | 3 |
| | 334444 | 6SLTGRAS230. | 0.0382 | 3 |
| | 334436 | 6P AC BK230. | 0.0370 | 3 |
| | 334435 | 6MID CO 230. | 0.0334 | 3 |
| | 334437 | 6KOLBS 230. | 0.0297 | 3 |
| | 334438 | 6HANKS 230. | 0.0272 | 3 |
| | 334445 | 6GULFWAY230. | 0.0187 | 3 |
| 12S-CW+SC | None (up to 1000 MW Transfer) | | | 1 |
| | 334057 | 4HUNTSVL138. | 0.0352 | 2 |
| | 334059 | 4WYNTEX 138. | 0.0347 | 2 |
| | 334058 | L558T485138. | 0.0333 | 2 |
| | 334056 | L558TP91138. | 0.0315 | 2 |
| | 334044 | 4DOBBIN 138. | 0.0290 | 2 |
| | 334060 | 4MT.ZION138. | 0.0285 | 2 |
| | 334053 | 4CINCINT138. | 0.0271 | 2 |
| | 334054 | 4WALKER 138. | 0.0264 | 2 |
| | 334066 | 4GEORGIA138. | 0.0263 | 2 |
| | 334052 | 4CEDAR 138. | 0.0262 | 2 |
| | 334442 | 6KEITHLA230. | 0.0500 | 3 |
| | 334443 | 6SOSIDE 230. | 0.0492 | 3 |
| | 334444 | 6SLTGRAS230. | 0.0491 | 3 |
| | 334436 | 6P AC BK230. | 0.0479 | 3 |
| | 334435 | 6MID CO 230. | 0.0443 | 3 |
| | 334437 | 6KOLBS 230. | 0.0404 | 3 |
| | 334438 | 6HANKS 230. | 0.0380 | 3 |
| | 334028 | 7GRIMES 345. | 0.0336 | 3 |
| | 334029 | 7FRONTR 345. | 0.0336 | 3 |
| | 334445 | 6GULFWAY230. | 0.0297 | 3 |
| 12S-CW-SC | None (up to 1000 MW Transfer) | | | 1 |
| | 334057 | 4HUNTSVL138. | 0.0343 | 2 |
| | 334059 | 4WYNTEX 138. | 0.0342 | 2 |
| | 334058 | L558T485138. | 0.0322 | 2 |
| | 334056 | L558TP91138. | 0.0310 | 2 |
| | 334044 | 4DOBBIN 138. | 0.0275 | 2 |
| | 334053 | 4CINCINT138. | 0.0269 | 2 |

| | | | | |
|---|---|---|---|---|
| | 334060 | 4MT.ZION138. | 0.0268 | 2 |
| | 334054 | 4WALKER 138. | 0.0263 | 2 |
| | 334066 | 4GEORGIA138. | 0.0261 | 2 |
| | 334052 | 4CEDAR 138. | 0.0257 | 2 |
| | 334442 | 6KEITHLA230. | 0.0518 | 3 |
| | 334443 | 6SOSIDE 230. | 0.0509 | 3 |
| | 334444 | 6SLTGRAS230. | 0.0508 | 3 |
| | 334436 | 6P AC BK230. | 0.0496 | 3 |
| | 334435 | 6MID CO 230. | 0.0462 | 3 |
| | 334437 | 6KOLBS 230. | 0.0420 | 3 |
| | 334438 | 6HANKS 230. | 0.0397 | 3 |
| | 334028 | 7GRIMES 345. | 0.0387 | 3 |
| | 334029 | 7FRONTR 345. | 0.0387 | 3 |
| | 334445 | 6GULFWAY230. | 0.0316 | 3 |

*Table 3-8: Branch Loading Violations at VS Limit for Sensitivity Scenarios.*

| Base Case | From Bus # & Name | | To Bus # & Name | | ID | % Load | Scenario # |
|---|---|---|---|---|---|---|---|
| 12S+CW-SC | 335368 | 8WELLS 500. | 335500 | 8WEBRE 500. | 1 | 103.5 | 1 |
| | 334067 | 6LEWISCR230. | 334072 | 4LEWIS 138. | 1 | 111.5 | 2 |
| | 335368 | 8WELLS 500. | 335500 | 8WEBRE 500. | 1 | 110.0 | 2 |
| | 334334 | 4LEACH 138. | 334335 | 4TOLEDO 138. | 1 | 125.2 | 3 |
| | 334362 | 6INLAND 230. | 334363 | 6HARTBRG230. | 1 | 123.9 | 3 |
| | 334333 | 4NEWTONB138. | 334334 | 4LEACH 138. | 1 | 123.5 | 3 |
| | 334281 | 4FORK CK138. | 334282 | 4RAYBURN138. | 1 | 121.0 | 3 |
| | 334361 | 6MCLEWIS230. | 334362 | 6INLAND 230. | 1 | 119.4 | 3 |
| | 334361 | 6MCLEWIS230. | 334368 | 6NEW OC 230. | 1 | 118.8 | 3 |
| | 334363 | 6HARTBRG230. | 334325 | 8HARTBRG500. | 2 | 117.7 | 3 |
| | 334363 | 6HARTBRG230. | 334325 | 8HARTBRG500. | 1 | 117.7 | 3 |
| | 335368 | 8WELLS 500. | 335500 | 8WEBRE 500. | 1 | 113.9 | 3 |
| | 334280 | 4DOUCETT138. | 334281 | 4FORK CK138. | 1 | 113.5 | 3 |
| | 335088 | 4MRSHAL 138. | 335125 | 4MOSSVL 138. | 1 | 111.7 | 3 |
| | 335125 | 4MOSSVL 138. | 335200 | 4NELSON 138. | 1 | 105.6 | 3 |
| | 335089 | 4HOLYWOD138. | 335200 | 4NELSON 138. | 1 | 104.1 | 3 |
| 12S-CW+SC | None (up to 1000 MW Transfer) | | | | | | 1 |
| | 334067 | 6LEWISCR230. | 334072 | 4LEWIS 138. | 1 | 115.4 | 2 |
| | 334334 | 4LEACH 138. | 334335 | 4TOLEDO 138. | 1 | 122.8 | 3 |
| | 334333 | 4NEWTONB138. | 334334 | 4LEACH 138. | 1 | 121.2 | 3 |
| | 334281 | 4FORK CK138. | 334282 | 4RAYBURN138. | 1 | 120.8 | 3 |
| | 334280 | 4DOUCETT138. | 334281 | 4FORK CK138. | 1 | 113.3 | 3 |
| | 334362 | 6INLAND 230. | 334363 | 6HARTBRG230. | 1 | 112.0 | 3 |
| | 335088 | 4MRSHAL 138. | 335125 | 4MOSSVL 138. | 1 | 110.1 | 3 |
| | 334363 | 6HARTBRG230. | 334325 | 8HARTBRG500. | 2 | 108.2 | 3 |
| | 334363 | 6HARTBRG230. | 334325 | 8HARTBRG500. | 1 | 108.2 | 3 |
| | 334361 | 6MCLEWIS230. | 334362 | 6INLAND 230. | 1 | 107.7 | 3 |
| | 334361 | 6MCLEWIS230. | 334368 | 6NEW OC 230. | 1 | 107.0 | 3 |
| | 335125 | 4MOSSVL 138. | 335200 | 4NELSON 138. | 1 | 106.7 | 3 |
| | 335089 | 4HOLYWOD138. | 335200 | 4NELSON 138. | 1 | 103.1 | 3 |
| 12S-CW-SC | None (up to 1000 MW Transfer) | | | | | | 1 |
| | 334067 | 6LEWISCR230. | 334072 | 4LEWIS 138. | 1 | 116.3 | 2 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | 334334 | 4LEACH 138. | 334335 | 4TOLEDO 138. | 1 | 125.2 | 3 |
| | 334333 | 4NEWTONB138. | 334334 | 4LEACH 138. | 1 | 123.5 | 3 |
| | 334281 | 4FORK CK138. | 334282 | 4RAYBURN138. | 1 | 121.6 | 3 |
| | 334280 | 4DOUCETT138. | 334281 | 4FORK CK138. | 1 | 114.1 | 3 |
| | 335088 | 4MRSHAL 138. | 335125 | 4MOSSVL 138. | 1 | 109.4 | 3 |
| | 334362 | 6INLAND 230. | 334363 | 6HARTBRG230. | 1 | 109.4 | 3 |
| | 335125 | 4MOSSVL 138. | 335200 | 4NELSON 138. | 1 | 106.6 | 3 |
| | 334363 | 6HARTBRG230. | 334325 | 8HARTBRG500. | 2 | 105.9 | 3 |
| | 334363 | 6HARTBRG230. | 334325 | 8HARTBRG500. | 1 | 105.9 | 3 |
| | 334361 | 6MCLEWIS230. | 334362 | 6INLAND 230. | 1 | 105.0 | 3 |
| | 334361 | 6MCLEWIS230. | 334368 | 6NEW OC 230. | 1 | 104.3 | 3 |
| | 335089 | 4HOLYWOD138. | 335200 | 4NELSON 138. | 1 | 102.5 | 3 |

# 4 Transient Security Studies

The transient simulations included the application of the specified Entergy and SPP contingencies both before and after the transfer. Damping was checked by Prony analysis of the time domain results. All simulations were stable and there were no criteria violations in any of the three base cases both before and after 1000 MW of transfer. The three sensitivity scenarios (described in Section 3.3) were also simulated, which showed no violations up to 1000 MW of their corresponding transfer.

The worst scenario was the tripping of 500250 (`DOLHILL7345.`) – 507760 (`SW SHV7 345.`) – circuit '1', along with 501813 (`G3RODEMR22.0`) unit '1', after a 5-cycle 3-phase fault at the first side (i.e., SPP N-2 contingency G1+L2). The worst transient voltage dip occurred at 500206 (`DOLHILL6230.`) with about 14 cycles duration, both before and after 1000 MW of transfer. This situation remained virtually the same for the three base cases.

# 5 Conclusions

Integration of the Entergy Texas, Inc. (ETI) grid into the SPP system was studied from voltage and transient security points of view. Three base cases representing 2012 summer peak conditions were considered, namely, with and without Cottonwood units, as well as adding 30% series compensation to Mt. Olive – Hartburg 500 kV line of the case without Cottonwood.

In this study a number of specific N-1 (consisting of one branch, either line or transformer), N-2 (consisting of one branch and one generating unit), and multiple contingencies (consisting of two or more branches) were considered. In dynamic simulations, 3-phase faults with appropriate fault durations were applied. The system was stressed through a transfer of generation from specific Entergy and SPP areas (i.e., increasing generation) to ETI (i.e., increasing load). The areas corresponding to the ETI grid and its surrounding regions in the Entergy and SPP systems were monitored for violations based on the Entergy and SPP criteria, whichever applicable.

With Cottonwood, voltage security analysis showed that 600 MW could be transferred against load increase in ETI before any voltage collapse. Without Cottonwood this limit was reduced to 450 MW, which remained virtually the same with or without series compensation of Mt. Olive – Hartburg 500 kV line. The limiting contingency was the combination of Lewis Creek unit '1' and China – Porter 230 kV line. The simulations showed no voltage security issues before the transfer. However, some moderate branch loading and bus voltage decline violations were observed as the transfer approached the corresponding voltage stability limits.

Sensitivity studies revealed that without Cottonwood the voltage stability limit could reduce to 100 MW of transfer against generation reduction in ETI if Lewis Creek unit 1 was out of service. This limit increased to 350 MW as a result of Mt. Olive – Hartburg 500 kV line series compensation. Similarly, if Sabine unit 5 was out of service these limits were 350 MW and 400 MW, respectively.

Transient security analysis revealed no criteria violation (i.e., transient stability, transient voltage dip, and damping) for any of the simulated contingencies, both before and after 1000 MW of transfer.

## Appendix 7: ROA Functionality Chart

SOUTHWEST POWER POOL

# Results by Functional Area

| ROA Activity | ERCOT | SPP |
|---|---|---|
| Customer Registration | • Initial Company/Profile data set up | • Initial Company/Profile data set up |
| Scheduling | • None | • All REPS will be treated as TCs and be required to follow TC processes and procedures |
| Wholesale Settlements | • Initial set-up and load profiling | • New process for receiving data from ETI – SCR727<br>• New process for Data validation<br>• New process for Load profiling |
| Invoicing | • None | • Non-ERCOT REP fee will need to be reviewed. Any associated administration fees will be allocated to REPs through SPP Settlements<br>• SPP will invoice TCs (or their agents) for balancing energy and associated fees |

SPP.ORG 4

## Appendix 8: ERCOT High Level Impact Analysis

| | |
|---|---|
| Impact Analysis Date | October 14, 2008 |
| Scope of Request | **Southwest Power Pool / Entergy Texas Inc. / Retail Open Access**<br><br>• ERCOT to assist Entergy Texas, Inc. (ETI) and affiliate Retail Electric Provider (REP) to complete the Retail Market Testing<br>• ERCOT to assist ETI working with Profiling Working Group for Weather Zone and Profile Tree approvals<br>• ERCOT to assist ETI with Profile ID assignments<br>• ERCOT to assist ETI with Load Research Sampling<br>• ERCOT to assist ETI to submit appropriate transactions to Load ~ 425,000 Electric Service Identifiers (ESI IDs) into ERCOT's registration database<br>• ERCOT to assist ETI affiliated REP to submit appropriate transactions to move-in ~ 425,000 ESI IDs<br>• ERCOT to assist ETI to submit appropriate initial meter reads for the ESI IDs<br>• ERCOT to produce ESI ID Service History and Usage Extract (aka SCR727 extract) – full – for ETI to give to Southwest Power Pool (SPP)<br>    o No new data elements are currently requested to be added to extract for SPP needs<br>• ERCOT to support the retail activities in the ETI territory of Texas.<br>• ERCOT to produce ongoing ESI ID Service History and Usage Extract daily for ETI to give to SPP |
| Cost/Budgetary Impact | Estimated cost: $250,000 – 500,000<br><br>ERCOT's system cost estimated to be $250,000<br><br>ERCOT's labor cost estimated to be $186,030 |

| | |
|---|---|
| | Breakdown of labor costs -<br><br>ERCOT's labor cost for supporting retail TDSP qualification is estimated to be $134,550.<br><br>• Retail Client Relations ongoing support and Market Participant registration (includes agreements, setup, communications and digital certificates) – $19,370.<br><br>• Load Profiling ongoing support and work with Profiling Working Group - $47,450.<br><br>• Retail Customer Choice ESI ID registration and monitoring - $27,560<br><br>• Market Operations Testing support for certification – $10,920<br><br>• Data Integrity and Analysis ongoing support for ESI ID account registration, extracts, and training - $29,250<br><br>ERCOT's labor cost for supporting ETI's LSE preparedness and qualification is estimated to be $51,480.<br><br>• Retail Client Relations ongoing support and Market Participant registration (includes agreements, setup, communications and digital certificates) – $19,370<br><br>• Retail Customer Choice ESI ID registration and monitoring - $11,440. |

| | |
|---|---|
| | • Market Operations Testing support for certification – $10,920.<br>• Data Integrity and Analysis ongoing support for ESI ID account registration, extracts, and training - $9,750 |
| Estimated Project Time Requirements*<br>*Unless otherwise indicated, project time requirements begin upon project initiation. | Approximately twenty-nine (29) months |
| ERCOT Staffing Impacts (across all areas) | No long term impact for Energy Analysis and Aggregation<br>No long term impact for Retail Customer Choice<br>No long term impact for Market Operations Testing<br>No long term impact for Data Integrity & Administration |
| ERCOT Computer System Impacts | Impact to the following systems for the addition of ~ 425,000 more ESI IDS, the associated increase in volume for retail transactions on those ESI IDs to support Retail Open Access, including monthly usage data that would be forwarded to REPs.<br><br>Inovis database<br>Siebel database<br>Lodestar database<br>Paperfree database and file system<br>TIBCO database<br>ETS database<br>ISM database<br>Storage<br><br>Limited Data Center Capacity<br>• Already at full capacity<br>• No relief until MET Center Disposition Project delivers more capacity<br>• Potentially not until 4Q2010 or 1Q2011<br>• Means we potentially can't "plug-in" another server until relief is realized |
| ERCOT Business Function Impacts | No long term impact for Energy Analysis and Aggregation<br>No long term impact for Retail Customer Choice<br>No long term impact for Market Operations Testing |

| | |
|---|---|
| | No long term impact for Data Integrity & Administration |
| Grid Operations & Practices Impacts | **None known** |

| Alternatives for a More Efficient Implementation ***(include explanation of impacts)*** |
|---|
| |

| Evaluation of Interim Solutions ***(e.g., manual workarounds)*** |
|---|
| |

| Feasibility of Implementation |
|---|
| **Impact on Resource Availability:**<br>Impact on Other Projects: |

| Comments |
|---|
| **This High Level Impact Analysis Report does** NOT **include the following aspects for wholesale or grid/network that were provided in 2006 as part of the Entergy Integration Report (Project No. 32217, *Entergy Gulf States Inc.'s Plan for Identifying Applicable Power Region Pursuant to PURA § 39.452(f)*)**<br><br>Transmission and Distribution Service Provider – **wholesale power transmission connectivity, communication, network modeling, settlement metering and data aggregation.** |

Resources – **registration, setup in ERCOT's network model and data aggregation systems.**

Qualified Scheduling Entities – **registration, telemetry testing, telecommunications, credit, network modeling, scheduling, bidding and deployments.**

Municipal Electric Utilities and Electric Cooperatives – **registration, testing and integration of meter points into ERCOT's metering, data aggregation and settlement systems.**